Surry Power Station
Units 1 and 2
Application for Subsequent License Renewal

October 2018

Intentionally Blank

List of Appendices

List of Tables

List of Figures

Surry Power Station

Units 1 and 2

Application for Subsequent License Renewal

Technical and Administrative Information

Intentionally Blank

1.0 ADMINISTRATIVE INFORMATION

1.1 GENERAL INFORMATION

1.1.1 NAME OF APPLICANT

The Applicant for the renewal of the first renewed operating licenses, referred to as subsequent license renewal, for Surry Power Station (SPS) Units 1 and 2 is Virginia Electric and Power Company (Dominion Energy Virginia or Dominion).

1.1.2 ADDRESS OF APPLICANT

Virginia Electric and Power Company
120 Tredegar Street
Richmond, VA 23219

1.1.3 DESCRIPTION OF BUSINESS OR OCCUPATION OF APPLICANT

Dominion Energy Virginia, incorporated in Virginia in 1909 as a Virginia public service corporation, is a wholly-owned subsidiary of Dominion Energy, Inc. and a regulated public utility that generates, transmits and distributes electricity for sale in Virginia. In Virginia, the company conducts business under the name “Dominion Energy Virginia” and primarily serves retail customers. In North Carolina, it conducts business under the name “Dominion Energy North Carolina” and serves retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, Dominion Energy Virginia sells electricity at wholesale prices to rural electric cooperatives, municipalities, and into wholesale electricity markets. All of Dominion Energy Virginia’s stock is owned by Dominion Energy, Inc.

Dominion Energy Virginia is the current licensed owner and operator of Surry Power Station Units 1 and 2, which are the subject of this subsequent license renewal application (SLRA). The current first renewed operating licenses will expire as follows:

- At midnight on May 25, 2032 for Unit 1 (Facility Operating License No. DPR-32).
- At midnight on January 29, 2033 for Unit 2 (Facility Operating License No. DPR-37).

Dominion Energy Virginia will continue as the licensed owner and operator for the subsequent renewed operating licenses.

1.1.4 DESCRIPTION OF ORGANIZATION AND MANAGEMENT OF APPLICANT

Dominion Energy Virginia is submitting this application on its own behalf. Otherwise, Dominion Energy Virginia is not acting as agent or representative of any other person in filing this application.

Dominion Energy Virginia is not owned, controlled or dominated by an alien, a foreign corporation, or a foreign government. All officers and directors are citizens of the United States. The names and business addresses of Dominion Energy Virginia's directors and officers as of September 1, 2018 are provided below:

Name	Business Address
Thomas F. Farrell, II Chairman, Chief Executive Officer	120 Tredegar Street Richmond, VA 23219
Mark F. McGettrick Director, Executive Vice President and Chief Financial Officer	120 Tredegar Street Richmond, VA 23219
Mark O. Webb Director, Senior Vice President – Corporate Affairs and Chief Innovation Officer	120 Tredegar Street Richmond, VA 23219
Robert M. Blue President and Chief Operating Officer – Power Delivery Group	120 Tredegar Street Richmond, VA 23219
Paul D. Koonce President and Chief Operating Officer – Power Generation Group	120 Tredegar Street Richmond, VA 23219
Carter M. Reid Executive Vice President, Chief Administrative & Compliance Officer and Corporate Secretary	120 Tredegar Street Richmond, VA 23219
Edward H. Baine Senior Vice President - Distribution	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
Gerald T. Bischof Senior Vice President – Nuclear Operations & Fleet Performance	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
P. Rodney Blevins Senior Vice President and Chief Information Officer	120 Tredegar Street Richmond, VA 23219

James R. Chapman Senior Vice President – Mergers & Acquisitions and Treasurer	120 Tredegar Street Richmond, VA. 23219
Katheryn B. Curtis Senior Vice President – Generation	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
Pamela F. Faggert Chief Environmental Officer and Senior Vice President – Sustainability	120 Tredegar Street Richmond, VA 23060
Daniel G. Stoddard Senior Vice President and Chief Nuclear Officer	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
Thomas P. Wohlfarth Senior Vice President – Regulatory Affairs	120 Tredegar Street Richmond, VA 23219
Corynne S. Arnett Vice President – Customer Service	120 Tredegar Street Richmond, VA 23219
Joshua J. Bennett Vice President – Technical Services	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
Carlos M. Brown Vice President and General Counsel	120 Tredegar Street Richmond, VA 23219
Michele L. Cardiff Vice President, Controller and Chief Accounting Officer	701 East Cary Street Richmond, VA 23219
David A. Craymer Vice President – System Operations	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23219
J. Kevin Curtis Vice President – Transmission	120 Tredegar Street Richmond, VA 23219
L. Wayne Duman Vice President – Financial Management	120 Tredegar Street Richmond, VA 23219
Simon C. Hodges Vice President – Corporate Strategy and Chief Risk Officer	120 Tredegar Street Richmond, VA 23219

Lee D. Katz Vice President – Financial Management	701 East Cary Street Richmond, VA 23219
Morenike K. Miles Vice President – Governance & Compliance and Assistant Corporate Secretary	120 Tredegar Street Richmond, VA 23219
Mark D. Mitchell Vice President – Generation Construction	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
Jeffrey A. Murphy Vice President – State Regulation	1201 East 55th Street Cleveland, OH 44103
Mark D. Sartain Vice President – Nuclear Engineering & Fleet Support	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
Alma W. Showalter Vice President – Tax	701 East Cary Street Richmond, VA 23219
Amanda B. Tornabene Vice President – Environmental Services	Innsbrook Technical Center 5000 Dominion Boulevard Glen Allen, VA 23060
Wendy T. Wellener Vice President – Shared Services	120 Tredegar Street Richmond, VA 23219
Charlene J. Whitfield Vice President – Distribution Operations	120 Tredegar Street Richmond, VA 23219
Keith Windle Vice President – Business Development	120 Tredegar Street Richmond, VA 23219
Joseph A. Woomer Vice President – Technical Solutions	701 East Cary Street Richmond, VA 23219
Steve C. Wooten Vice President – Information Technology	707 East Main Street Richmond, VA 23219
N. Larry Lane Site Vice President – North Anna	North Anna Power Station 1022 Haley Drive Mineral, VA 23117

Fred Mladen
Site Vice President – Surry

Surry Power Station
5570 Hog Island Road
Surry, VA 23883

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

Dominion Energy Virginia requests renewal of the initial renewed operating licenses for a period of 20 years beyond the current expiration dates shown below to permit the continued generation and distribution of electric energy:

Unit	License No.	License Class	Expiration Date
1	DPR-32	104b	May 25, 2032
2	DPR-37	104b	January 29, 2033

In this SLRA, Dominion Energy Virginia also requests renewal of the source, special nuclear material, and by-product licenses that are included within the renewed operating licenses and that were issued pursuant to 10 CFR Parts 30, 40, and 70.

1.1.6 EARLIEST AND LATEST DATES FOR ALTERATIONS, IF PROPOSED

No physical plant alterations or modifications have been identified as necessary in order to implement the provisions of this SLRA.

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 not expected that any such information will become involved in these licensed activities.

In accordance with the requirements of 10 CFR 54.17(g), Dominion Energy Virginia 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, Virginia State Corporation Commission and the North Carolina Utilities Commission are the principal regulators of Dominion Energy Virginia’s electric operations in Virginia and North Carolina. The names and addresses of these regulatory agencies are as follows:

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Joel H. Peck, Clerk
Virginia State Corporation Commission
1300 East Main Street
Tyler Building - First Floor
Richmond, Virginia 23218

Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

1.1.9 LOCAL NEWS PUBLICATIONS

Local news publications that circulate in the area around SPS are as follows:

Richmond Times-Dispatch
300 E. Franklin St.
Richmond, VA 23219

Virginia Gazette
216 Ironbound Road
Williamsburg, VA 23188

Smithfield Times
P.O. Box 366
Smithfield, VA 23431

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-45) for SPS 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. 12, lists SPS operating license numbers DPR-32 and DPR-37. Dominion Energy Virginia has reviewed the original Indemnity Agreement and the Amendments. Neither Article VII nor Item 3 of the Attachment specifies an expiration date for license numbers DPR-32 and DPR-37. Therefore, no changes to the Indemnity Agreement are deemed necessary as part of this application. Should the license numbers be changed by NRC upon issuance of the subsequent renewed licenses, Dominion Energy Virginia 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 Nuclear Regulatory Commission (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 Virginia will maintain a summary list in the Updated Final Safety Analysis Report (UFSAR) of activities that are required to manage the effects of aging for the systems, structures or components within the scope of subsequent license renewal during the subsequent period of extended operation and summaries of the time-limited aging analyses evaluations.

1.2.2 INCORPORATION BY REFERENCE

With the exception of the following three instances in the Environmental Report, there are no documents incorporated by reference as part of the SLRA:

- The analyses for certain impacts codified by rulemaking (61 FR 28483) for Category 1 issues
- The findings in NUREG-1437, Revision 1, for the applicable issues (Reference 1.7-19)
- The NRC findings for the 53 Category 1 issues that apply to SPS (plus the one uncategorized issue for which the NRC came to no generic conclusion)

Other document references, either in text or in General References are listed for information only.

1.2.3 CONTACT INFORMATION

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

Mr. Daniel G. Stoddard
Senior Vice President and Chief Nuclear Officer
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711
(Daniel.G.Stoddard@dominionenergy.com)

with copies to:

Mr. Mark D. Sartain
Vice President - Nuclear Engineering and Fleet Support
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711
(Mark.Sartain@dominionenergy.com)

Mr. Fred Mladen
Site Vice President - Surry
Surry Power Station
5570 Hog Island Road
Surry, VA 23883-0315
(Fred.Mladen@dominionenergy.com)

Mr. B. L. (Sonny) Stanley
Director - Nuclear Regulatory Affairs
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711
(Sonny.Stanley@dominionenergy.com)

Mr. Paul Aitken
Manager - Nuclear Engineering
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711
(Paul.Aitken@dominionenergy.com)

Michael Regulinski, Esq.
Managing General Counsel
Dominion Energy Services, Inc.
120 Tredegar Street, RS-2
Richmond, Virginia 23219
(michael.regulinski@dominionenergy.com)

Kathryn M. Sutton, Esq.
Morgan, Lewis & Bockius LLP
1111 Pennsylvania Ave NW
Washington, DC 20004
(Kathryn.Sutton@morganlewis.com)

1.3 PURPOSE

This document provides information required by 10 CFR Part 54 to support the SLRA for renewal of the initial renewed operating licenses. 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

Surry Power Station Units 1 and 2 are located on a site situated on Gravel Neck, adjacent to the James River in Surry County, Virginia. Each unit includes a three-coolant-loop, pressurized light water reactor nuclear steam supply system, and a turbine generator all of which are furnished by Westinghouse Electric Corporation. Each reactor unit was initially operated at a licensed power output of 2,441 MWt with a gross electrical output of 822.6 MWe.

In 1995, both units were uprated to the design values that correspond to a core power output of 2,546 MWt with an expected gross electrical output of 855.4 MWe.

In 2010, both units were uprated to a core power output of 2,587 MWt (corresponding to a nuclear steam supply system power rating of 2,599 MWt).

Dominion Energy Virginia also operates an independent spent fuel storage installation (ISFSI) at the site. The reinforced concrete pads at the ISFSI designated as Pads 1 and 2 are operated under a separate license issued pursuant to the provisions of 10 CFR 72 (Reference 1.7-1). ISFSI Pad 3 and a fourth pad, currently under construction, are licensed pursuant to the general license provisions contained in NRC regulations in 10 CFR 72.210. Therefore, the ISFSI is not in-scope of subsequent license renewal as reflected in Table 2.2-1.

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 licenses 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 1.7-5) and NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal." (Reference 1.7-6) 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 1.7-3) NUREG-2192 references NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report." (Reference 1.7-4) 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

Chapter 1 provides the administrative information required by 10 CFR 54.17 and 10 CFR 54.19. It 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 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. Scoping results are presented in Section 2.2, Table 2.2-1. Screening results are presented 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 period of extended operation. Section 3.0 presents the results of the AMRs. 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 Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, SRP-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 system, 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 chapter.Section 4.0 includes each of the TLAAs identified in SRP-2192 and in plant-specific analyses. This chapter 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 no 10 CFR 50.12 exemption involving a TLAA as defined in 10 CFR 54.3 is required during the subsequent period of extended operation. The information in Section 4.0 fulfills the requirements in 10 CFR 54.21(c).

Appendix A - UFSAR Supplement

As required by 10 CFR 54.21(d), the Updated Final Safety Analysis Report (UFSAR) supplement is found in Appendix A and contains a summary of activities credited for managing the effects of aging for the period of extended operation. In addition, summary descriptions and dispositions of TLAA evaluations and a summary of license renewal commitments are provided. The 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 and activities that are credited for managing aging effects for components or 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 - MRP-227-A Gap Analysis for PWR Vessel Internals Aging Management

Appendix C satisfies the requirements of NUREG-2192 Section 3.1.2.2.9 to provide a gap analysis of the components that are within the scope of the PWR Vessel Internals B2.1.7 program. Using an MRP-227-A based program (i.e. EPRI 1022863, Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines) as a starting point, the gap analysis is a basis for identifying and justifying potential changes to the program that will manage aging degradation effects for reactor vessel internal components during the subsequent period of extended operation.

Appendix D - Technical Specification Changes

Appendix D satisfies the requirements of 10 CFR 54.22 to identify whether any Technical Specification changes or additions are necessary to manage the effects of aging during the period of extended operation. 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 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
AEC	Atomic Energy Commission
AFW	Auxiliary Feedwater
ALE	Adverse Localized Environments
AMA	Aging Management Activity
AMP	Aging Management Program
AMR	Aging Management Review
AMSAC	ATWS Mitigation System Actuation Circuit
ANSI	American National Standards Institute
API	American Petroleum Institute
AS	Auxiliary Steam
ASCO	Automatic Switch Company
ASME	American Society of Mechanical Engineers
ASR	Alkali-Silica Reaction
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transients Without SCRAM
AVB	Anti-Vibration Bar

Table 1.6-1 Acronyms

Acronym	Definition
B&W	Babcock and Wilcox
BC	Bearing Cooling
BD	Blowdown
BIW	Boston Insulated Wire
BMI	Bottom Mounted Instrumentation
BR	Boron Recovery
BTP	Branch Technical Position
CAS	Central Alarm Station
CASS	Cast Austenitic Stainless Steel
CAT	Chemical Addition Tank
CC	Component Cooling
CCHX	Component Cooling Heat Exchanger
CCVT	Captive Coupled Voltage Transformer
CD	Chilled Water
CD-ROM	Compact Disk-Read only Memory
CEI	Chemistry Effectiveness Indicator
CFR	Code of Federal Regulations
CFRP	Carbon Fiber Reinforced Polymer
CH	Chemical Volume and Control
CISIs	Containment Inservice Inspections
CLB	Current Licensing Basis
CN	Condensate

Table 1.6-1 Acronyms

Acronym	Definition
CP	Condensate Polishing
CP	Cathodic Protection
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CRGT	Control Rod Guide Tube
CrMo	Chromium-Molybdenum
CS	Containment Spray
CSA	Conductor Seal Assembly
CSPE	Chlorosulfonated Polyethylene
Cu-Ni	Copper Nickel
CUF	Cumulative Usage Factor
CV	Containment Vacuum
CvUSE	Charpy Upper Shelf Energy
CW	Circulating Water
DA	Degradation Assessments
DA	Drains-Aerated
DB	Drains-Building Services
DBE	Design Basis Event
DC	Direct Current
DCP	Design Change Package
DG	Drains-Gaseous
DGSS	Diesel Generator Support Systems

Table 1.6-1 Acronyms

Acronym	Definition
DLPS	Drains and Liquid Processing Systems
EAF	Environmentally Assisted Fatigue
ECCS	Emergency Core Cooling Systems
ECMT	Emergency Condensate Makeup Tank
ECSA	Electrical Conductor Seal Assembly
ECST	Emergency Condensate Storage Tank
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EDS	Equipment Data System
EFPY	Effective Full-Power Years
EHC	Electro-hydraulic Control
EPDM	Ethylene Propylene Diene Monomer
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQML	Equipment Qualification Master List
ESF	Engineered Safety Features
ESGR	Emergency Switchgear Room
ESW	Emergency Service Water
ESWPH	Emergency Service Water Pump House
ET	Eddy Current Test
ETA	Ethanolamine

Table 1.6-1 Acronyms

Acronym	Definition
EVT	Enhanced Visual Test
FAC	Flow Accelerated Corrosion
FAO	Free Available Oxidant
FC	Fuel Pit Cooling
FCG	Fatigue Crack Growth
FME	Foreign Materials Exclusion
FMECA	Failure Modes, Effects, and Criticality Analysis
FMR	Flame and Moisture Resistant
FP	Fire Protection
FPSS	Fire Protection and Supporting Systems
FRP	Fiberglass Reinforced Plastic
FSAR	Final Safety Analysis Report
FSER	Final Safety Evaluation Report
FW	Feedwater
FWST	Fire Water Storage Tank
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GDC	General Design Criterion
GE	General Electric
GL	Generic Letter
HELB	High-Energy Line Break
HG	Hydrogen Gas
HHSI	High-Head Safety Injection

Table 1.6-1 Acronyms

Acronym	Definition
HLIS	High-Level Intake Structure
HMWPE	High Molecular Weight Polyethylene
HRSS	High Radiation Sampling System
HV	Heating and Ventilation
HVAC	Heating, Ventilation, and Air Conditioning
HVT	High-Voltage Termination
I&C	Instrumentation and Controls
IA	Instrument Air
IARC	Interim Alternate Repair Criteria
IASCC	Irradiation-Assisted Stress Corrosion Cracking
IC	Incore Instrumentation
ICCS	Inadequate Core Cooling System
ICES	INPO Consolidated Event System
ID	Inner Diameter
IE	Inspection and Enforcement
IE	Irradiation Embrittlement
IEB	Inspection and Enforcement Bulletin
IEN	Inspection and Enforcement Notice
IGSCC	Intergranular Stress Corrosion Cracking
ILRT	Integrated Leak Rate Test
IN	Information Notice
INEL	Idaho National Engineering Laboratories

Table 1.6-1 Acronyms

Acronym	Definition
INPO	Institute of Nuclear Power Operations
IPA	Integrated Plant Assessment
IR	Insulation Resistance
ISR/IC	Irradiation-Induced Stress Relaxation and Creep
ISFSI	Independent Spent Fuel Storage Installation
ISG	Interim Staff Guidance
ISI	Inservice Inspection
ISRS	Inside Recirculation Spray
ITG	Issues Task Group
Ksi	Kilo-pounds per square inch
LAR	License Amendment Request
LAW	Lower Axial Weld
LBB	Leak-Before-Break
LCMP	Life Cycle Management Program
LFET	Low Frequency Electromagnetic Examination Techniques
LFW	Lower Flange Weld
LGW	Lower Girth Weld
LHSI	Low-Head Safety Injection
LLIS	Low-Level Intake Structure
LLRT	Local Leak Rate Test
LM	Leakage Monitoring
LOCA	Loss-of-Coolant Accident

Table 1.6-1 Acronyms

Acronym	Definition
LP	Liquid penetrant
LR	License Renewal
LRA	License Renewal Application
LTOPS	Low Temperature Overpressure Protection System
LW	Liquid and Solid Waste
MAW	Middle Axial Weld
MCR	Main Control Room
MEB	Metal Enclosed Bus
MIC	Microbiologically Influenced Corrosion
MIRVSP	Master Integrated Reactor Vessel Surveillance Program
MOV	Motor Operated Valve
MPs	Megapascals
MRP	Material Reliability Program
MS	Main Steam
MUR	Measurement Uncertainty Recapture
MWe	Megawatt-electric
MWt	Megawatt-thermal
NACE	National Association of Corrosion Engineers
NAPS	North Anna Power Station
NDE	Non-destructive Examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association

Table 1.6-1 Acronyms

Acronym	Definition
NI	Nuclear Instrumentation
NPS	Nominal Pipe Size
NRC	U.S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	Nuclear Steam Supply System
NST	Neutron Shield Tank
OCCWS	Open Cycle Cooling Water System
OE	Operating Experience
OOS	Out of Specification
OSRS	Outside Recirculation Spray
P-T	Pressure-Temperature
PAG	Predictive Analysis Group
PDI	Performance Demonstration Initiative
PEO	Period of Extended Operation
PG	Primary Grade
PI	Polarization Index
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
PT	Penetrant Testing
PTS	Pressurized Thermal Shock
PU	Power Uprate
PWR	Pressurized Water Reactor

Table 1.6-1 Acronyms

Acronym	Definition
PWROG	Pressurized Water Reactor Owners Group
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QDR	Qualification Documentation Report
QS	Quench Spray
RAI	Request for Additional Information
RC	Reactor Coolant
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RCSC	Research Council for Structural Corrections
RFO	Refueling Outage
RG	Regulatory Guide
RH	Residual Heat Removal
RM	Radiation Monitoring
RO	Restricting Orifice
RS	Recirculation Spray
RSST	Reserve Station Service Transformer
RTD	Resistance Temperature Devices
RT_{NDT}	Reference nil ductility transition temperature
RT_{PTS}	Reference temperature for pressurized thermal shock
RV	Reactor Vessel
RVI	Reactor Vessel Internals

Table 1.6-1 Acronyms

Acronym	Definition
RVLIS	Reactor Vessel Level Instrumentation System
RVWG	Reactor Vessel Working Group
RWST	Refueling Water Storage Tank
SA	Service Air
SBO	Station Blackout
SC	Structures and Components
SCC	Stress Corrosion Cracking
SCC-W	Stress Corrosion Cracking at a Weld
SCS	Secondary Core Support
SD	Steam Drains
SDBD	System Design Basis Document
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SG	Steam Generator
SI	Safety Injection
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SOV	Solenoid Operated Valve
SPCS	Steam and Power Conversion Systems
SPS	Surry Power Station
SR	Silicone Rubber
SRF	Surry Repair Facility

Table 1.6-1 Acronyms

Acronym	Definition
SRP	Standard Review Plan
SS	Sampling System
SSCs	Systems, Structures, and Components
SST	Station Service Transformer
SW	Service Water
TE	Thermal Embrittlement
T.S.	Technical Specification
TGSCC	Transgranular Stress Corrosion Cracking
TLAA	Time-Limited Aging Analyses
TR	Technical Report
UAW	Upper Axial Weld
UFSAR	Updated Final Safety Analysis Report
UFW	Upper Flange Weld
UGW	Upper Girth Weld
UPTI	Underground Piping and Tanks Initiative
USE	Upper Shelf Energy
UT	Ultrasonic / Ultrasonic Testing
VCT	Volume Control Tanks
VHP	Vessel Head Penetration
VS	Void Swelling
VT	Visual Test

Table 1.6-1 Acronyms

Acronym	Definition
WCP	Work Control Process
WOG	Westinghouse Owners' Group
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 NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants.”

1.7-4 NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report.”

1.7-5 Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses.”

1.7-6 NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,” December 2017.

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 Surry Power Station Units 1 and 2 Technical Specifications, Change 53.

1.7-18 Surry Power Station Updated Final Safety Analysis Report (UFSAR), Revision 49, September 28, 2017.

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

Intentionally Blank

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 Surry Power Station (SPS) 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 2.0 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 SPS 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 1.7-6). 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 following SLRA sections:

- Section 2.3 for mechanical systems
- Section 2.4 for structures
- 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 at SPS. 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 then 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. Structures that are within the scope of subsequent license renewal that are located in or adjacent to the protected area are shown on a subsequent license renewal boundary drawing. 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 1.7-3), 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 SPS 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 UFSAR 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 Updated Final Safety Analysis Report

There is a common Updated Final Safety Analysis Report (UFSAR) for SPS. The UFSAR is updated regularly in accordance with the requirements of 10 CFR 50.71(e). The UFSAR provided significant input for system and structure descriptions and functions.

2.1.2.2 Engineering Drawings

Engineering Drawings at SPS 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 SPS equipment database is contained within the Plant Asset Management System (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 Fire Protection Report

There is a common Fire Protection (Appendix R) Report for SPS. The SPS Fire Protection (Appendix R) Report 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.

2.1.2.5 Maintenance Rule System Basis Database

The maintenance rule system basis database documents the results of maintenance rule scoping for SPS 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

Electrical equipment and components that must be environmentally qualified are identified in PAMS. The PAMS equipment database is discussed in Section 2.1.2.3. The database includes a listing of equipment and components, and includes fields that identify specific equipment information including a controlled field for environmental qualification level.

2.1.2.7 Other CLB References

- Application for Renewed Operating Licenses, Surry Power Station Units 1 and 2 (Initial LRA).
- NUREG-1766, Safety Evaluation Report Related to the License Renewal of North Anna Power Station, Units 1 and 2, and Surry Power Station, Units 1 and 2.
- NRC Safety Evaluation Reports (SERs) include NRC staff review of SPS 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 SPS 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 systems and structures at SPS, 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

SPS UFSAR, 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 SPS subsequent license renewal systems and structures is based on the SPS UFSAR and the guidance of NUREG-2191 “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” Final Report (Reference 1.7-4). 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. SPS plant components that have been classified as safety-related are identified as “SR” in the controlled safety classification data field in PAMS. SPS safety-related functions described in the UFSAR were evaluated against system functions to confirm the PAMS safety-related classification. SPS safety classification procedures were reviewed against the subsequent license renewal safety-related scoping criterion in 10 CFR 54.4(a)(1) to confirm that SPS safety-related classification are consistent with subsequent license renewal requirements.

The SPS definition of safety-related is as follows:

Safety-related structures, systems and components that are relied upon to remain functional during and following design basis events to ensure:

- *The integrity of the reactor coolant pressure boundary*
- *The capability to shut down the reactor and maintain it in a safe shutdown condition, or*
- *The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in Sec. 50.34(a)(1), 50.67(b)(2) or 100.11, as applicable.*

This definition is equivalent to 10 CFR 54.4(a)(1) for the purposes of subsequent license renewal scoping. The wording difference is addressed as follows:

Design Basis Events

The SPS definition of safety-related does not reference 10 CFR 50.49(b)(1) to define design basis events (DBEs). However, the SPS definition of design basis events is:

Those events that establish the conditions for which the plant is designed. DBEs include the following:

- *Normal operation*
- *Anticipated operational occurrences/transients*
- *Design basis accidents*
- *External events*
- *Natural phenomena*

This definition corresponds to that provided in 10 CFR 50.49(b)(1).

Therefore, the SPS definition of safety-related 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 SPS UFSAR 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 physical or spatial interactions and describes the SPS approach to scoping of nonsafety-related systems with a potential for physical or spatial interaction with safety-related SSCs. SPS chose to implement the preventive option as described in NEI 95-10, Appendix F (as referenced by NEI 17-01). 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 scope of systems and structures required for the fire protection program to comply with the requirements of 10 CFR 50.48 includes:

- Systems and structures required to demonstrate post-fire safe shutdown capabilities
- Systems and structures required for fire detection and suppression
- Systems and structures required to meet commitments made to Appendix A of Branch Technical Position (BTP) APCSB 9.5-1

UFSAR, 9.10.1 confirms that SPS satisfies the regulatory criteria set forth in General Design Criterion 3, in 10 CFR 50, Appendix R (Sections III.G, III.J, III.L and III.O), and in Appendix A to Branch Technical Position APCSB 9.5-1. The fire protection program for SPS has been found, in NRC Safety Evaluation Reports, to satisfy the regulatory criteria set forth in these two documents. Fire protection system and structure scoping for SPS is performed consistent with this guidance, and is documented in the technical basis document.

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. For the listed systems and structures, the technical basis document also identifies appropriate CLB references. 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 at SPS 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 identified in the UFSAR. Those portions 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 portions of the fire suppression and detection systems that are included within the scope of subsequent license renewal are identified in the technical basis document. Those portions of fire detection and suppression systems that are attached to in-scope portions of the system, but not included in scope, can be isolated from the in-scope portion of the system by closing the associated isolation valve. 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. The PAMS component database contains a controlled field that identifies components within the EQ program.

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 SPS 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 SPS 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 UFSAR Section 7.2.3.2.7, Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC). The AMSAC consists of a diverse method to mitigate the consequences of an ATWS event by isolating steam generator blowdown, initiating the auxiliary feedwater system, initiating a turbine trip, and tripping the rod control system motor-generator sets to shut down the reactor under conditions indicative of an ATWS.

The SPS 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 analysis 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. SPS has developed a four-hour coping analysis and installed an alternate AC system to address the requirements of 10 CFR 50.63. SPS UFSAR Section 8.4.6, Alternate AC (AAC) System, discusses the AAC diesel generator capacity and capability, SBO coping duration, and bus alignments.

SPS is interconnected to the transmission system through switchyards operating at 500 kV and 230 kV. Both switchyards are of the “breaker and a half” design. The 500 kV switchyard has three 500 kV lines that connect to three independent substations within the VEPCO transmission system. The 230 kV switchyard has six 230 kV lines that connect to five independent substations within the VEPCO transmission system and two 230 kV lines that connect to the Gravel Neck combustion turbine site near SPS. The 500 kV and 230 kV switchyards are independent and provide two independent sources of power to the 34.5 kV switchyard that provides reserve station service power to the units. The 34.5 kV switchyard consists of buses 5, 6, and 7, with bus 5 supplied from the 500 kV switchyard through transformer 1, bus 6 supplied from the 230 kV switchyard through transformer 2, and bus 7 supplied from the 230 kV switchyard through transformer 4. This arrangement reflects a design change issued in 2006 that reconfigured the 34.5 kV switchyard to increase reliability and flexibility of the offsite power source by providing independent sources of power to buses 5 and 6, and adding bus 7 as an alternate source to either bus 5 or 6.

Three reserve station service transformers (RSSTs) supply offsite power to station transfer buses D, E, and F. RSST A and B receive power from 34.5 kV switchyard bus 5 and supply power to transfer buses D and E. RSST C receives power from 34.5 kV switchyard bus 6 and supplies power to transfer bus F. Bus 7 is available as a backup to either Bus 5 or Bus 6. Transfer bus D powers emergency bus 1J (Unit 1), transfer bus E powers emergency bus 2H (Unit 2), and transfer bus F powers emergency buses 1H and 2J (Units 1 and 2, respectively). Electrical distribution system cables are routed from buses 5, 6, and 7 to the RSSTs via buried conduit, cable trenches, manholes, duct banks, and overhead distribution poles and insulators. From the RSSTs, the electrical distribution system is routed to the turbine building via overhead switchyard (tubular) bus supported by steel structures. At the turbine building, cables attached to the tubular bus are routed via cable trays to the normal switchgear room where they connect to the D, E and F transfer buses.

The boundary for the offsite SBO recovery path is the first circuit breaker and associated disconnect switches downstream of buses 5, 6, and 7. This boundary is consistent with the NRC standard review plan for subsequent license renewal, NUREG-2192, section 2.5.2.1.1 boundary definition for the station blackout recovery path. The NUREG states that the in-scope plant system portion of the offsite power system includes equipment out to the first circuit breaker with the offsite distribution system. This path typically includes the circuit breakers that connect to the offsite system power transformers (reserve station service transformers for SPS), the transformers, the intervening overhead and underground circuits between circuit breaker and transformer, and transformer and onsite electrical distribution system, and the associated control circuits and structures.

Structures and components that comprise the offsite SBO recovery path include:

- 34.5 kV circuit breakers (circuit breaker numbers 152, 252, 462, 172, 272, and 472) with associated control components (including cables) and disconnect switches (disconnect switch numbers 154, 254, 464, 155, 255, 465, 174, 274, 474, 175, 275, and 475) to connect the reserve station service transformer circuits to the transmission system
- 34.5 kV power conductors (insulated cable, transmission conductors, switchyard bus, and connectors) from the switchyard to the reserve station service transformers and 4160 V conductors (insulated cable, switchyard bus, and connectors) from the reserve station service transformers to the transfer buses D, E, and F
- Power cables and connectors for sump pumps located in manholes associated with underground 34.5 kV cable
- High voltage insulators used with transmission conductors, and switchyard bus for 34.5 kV and 4160 V circuits
- Transfer buses D, E, and F, and the incoming 4160 V breakers for each transfer bus (15D1, 15E1, and 15F1)
- Manholes and ducts containing 34.5 kV insulated cables (Manhole sump pumps are included in the plumbing system)
- Steel support structures and concrete foundations that support switchyard circuit breakers, disconnect switches, and power conductors
- Wooden poles that support 34.5 kV power conductors
- Switchyard control houses

The SBO coping and recovery paths are shown in Figure 2.1-1, SBO Coping and Recovery Paths.

SBO coping is accomplished by the AAC generator supplying an emergency bus on each unit through transfer buses D and E. The coping supply path from the AAC generator to the transfer buses is through breaker 05M4 to the 0M bus, through breakers 05M3 and 05L2 to the 0L bus, and through breaker 05L3 to the D transfer bus and breaker 05L1 to the E transfer bus. The D transfer bus then supplies the 1J emergency bus on Unit 1 through breaker 15J8 and the E transfer bus supplies the 2H emergency bus on Unit 2 through breaker 25H8.

The SBO recovery path from offsite power is from either bus 5, 6, or 7 through RSST A, B, or C to transfer bus D, E, or F. Bus 5 supplies transfer bus D through switchyard breaker 152 and transfer bus E through switchyard breaker 252. Bus 6 supplies transfer bus F through switchyard breaker 462. Alternately, Bus 7 can supply transfer bus D through switchyard breaker 172, transfer bus E through switchyard breaker 272, or transfer bus F through switchyard breaker 472. The transfer buses then power at least one emergency bus on each unit as follows: transfer bus D powers Unit 1 emergency bus 1J through breaker 15J8, transfer bus E powers Unit 2 emergency bus 2H through breaker 25H8, and transfer bus F powers Unit 1 emergency bus 1H through breaker 15H8 and/or Unit 2 emergency bus 2J through breaker 25J8.

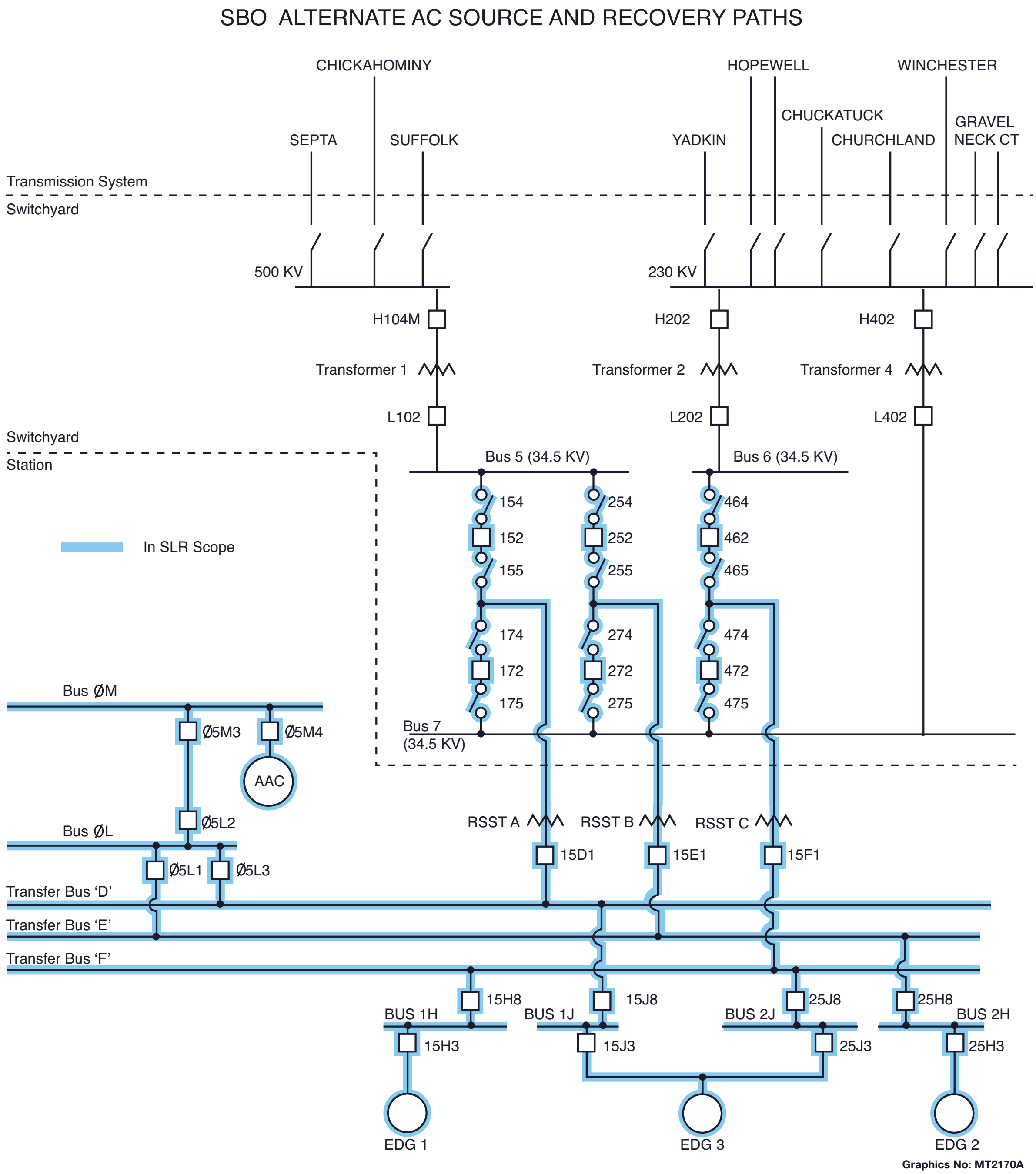
The SBO recovery path from onsite power is from the emergency diesel generators. EDG 1 powers Unit 1 emergency bus 1H through breaker 15H3, EDG 2 powers Unit 2 emergency bus 2H through breaker 25H3 and EDG 3 powers either Unit 1 emergency bus 1J through breaker 15J3 or Unit 2 emergency bus 2J through breaker 25J3.

Restoration of a 34.5 kV circuit through RSST A, B, or C, or an emergency diesel generator, meets the definition of recovery by re-powering the plant AC distribution system from offsite sources or onsite emergency AC sources, and terminates the SBO event.

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.

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 Coping and Recovery Paths



2.1.4 SCOPING METHODOLOGY

The scoping process is the systematic process used to identify the SPS 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. System and structure scoping evaluations are documented and have been retained in a subsequent license renewal database. The system and structure scoping results are provided in Section 2.2.

The SPS 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 SPS 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 Sections 2.1.4.1, 2.1.4.2, and 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.*

At SPS, the safety-related plant components are identified in controlled engineering drawings and in the PAMS database. The safety-related classifications in the SPS 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 PAMS safety classification, system and structure descriptions and analyses in the UFSAR, or on design basis documents such as engineering drawings, evaluations, or calculations. Systems and structures that are identified as safety-related in the UFSAR 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.

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.

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 are 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 nonsafety-related SSCs that were included within the scope of subsequent license renewal to support a safety-related SSC in performing a 10 CFR 54.4(a)(1) intended function are identified on the subsequent license renewal boundary drawings in blue.

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

1. The circulating water system main condenser inlet and outlet valves are classified as safety-related because they are required to close for a number of design basis events to ensure adequate intake canal level. The portion of the circulating water system between the condenser inlet and outlet valves is nonsafety-related; however, it is required to maintain its pressure-retaining capability during those design basis events.
2. The turbine over-speed tripping devices, the stop valves, the throttle/governor valves, and the associated electro-hydraulic control system are relied on to prevent excessive turbine over-speed conditions that could lead to turbine rotor/disk failures, resulting in the generation of turbine missiles greater than those assumed in the UFSAR evaluations. However, the affected components fail to their safe condition, and the passive pressure boundary function of the valve bodies, the associated piping, and the EHC system are not needed to prevent turbine over-speed. Additionally, the valve internals and over-speed tripping devices are specifically excluded from an aging management review as active components.

3. The condensate system emergency condensate makeup tank, together with the feedwater booster pumps and associated flowpaths, provides a backup source of water to the suction of auxiliary feedwater pumps at either unit, so that the auxiliary feedwater pumps at either unit can supply auxiliary feedwater to both units (via a discharge cross-connect line).
4. The fuel pool cooling system removes heat from the spent fuel pool during normal operation.
5. The neutron shield tank cooling system provides shield tank cooling during normal operation.
6. The plumbing system turbine building sump pumps and discharge piping mitigate plant flooding.
7. The plumbing system removes water from the containment sub-surface drains to minimize hydrostatic pressure on the containment mat liner.
8. The plumbing system storm drains remove water from the yard area during maximum precipitation events to mitigate flooding.
9. The service water system expansion joints at the bearing cooling water heat exchangers have enclosures to mitigate the potential for flooding in the Turbine Building.
10. The ventilation system auxiliary building central exhaust fans and associated ducting provide ventilation for the charging pump cubicles.
11. Some nonsafety-related portions of systems are connected to safety-related (or (a)(2) functional) systems such that a portion of the nonsafety-related system must retain its pressure boundary integrity to support the integrity of the attached system. This function applies to the following systems:
    a. Steam generator blowdown
    b. Component cooling
    c. Condensate
    d. Instrument air
    e. Primary grade water
    f. Vacuum priming
    g. Boron recovery
    h. Reactor cavity purification
    i. Liquid waste

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).

A supporting system review was performed as an additional confirmation of scoping to meet 10 CFR 54.4(a)(2) criteria. The scoping process was performed on a system and structure basis. For systems included within the scope of subsequent license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), the scoping evaluation included the identification of any additional systems, including nonsafety-related systems, that are required to support the safety-related system intended functions. It was then confirmed that these identified systems were also included in scope. Except as identified above, the SPS systems required to support 10 CFR 54.4(a)(1) were classified safety-related, and as such included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1). The identification of support systems was not required for structures since structural intended functions do not rely on supporting systems.

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 SPS 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 per 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.
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 (ten, at SPS), 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 restrains, 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 at SPS although mitigative features are included as 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.

SPS applied the preventive option for 10 CFR 54.4(a)(2) scoping. The preventive option as implemented at SPS is based upon a “spaces” approach for determining potential for spatial interactions with safety-related SSCs. The boundaries for the “spaces” are structure boundaries 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.

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. 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. SPS 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 at SPS 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 systems 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 identified on the subsequent license renewal boundary drawings in orange.

Scoping of Abandoned Mechanical Components

There are mechanical fluid components at SPS 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.

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, or a function that demonstrated 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 the PAMS database 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 UFSAR sections, and other licensing 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 associated with the structure proper (e.g., bolting for beams, braces, and columns for the building structure) is evaluated with the structure. Structural bolting associated with a component support or other structural commodity components are evaluated with the component support or structural commodity components. A subsequent license renewal boundary drawing was created that shows in-scope structures located in or adjacent to the protected area.

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 the PAMS equipment database by system designation code. The PAMS equipment database does not list electrical component types such as high-voltage transmission conductors, high voltage insulators, and switchyard bus and connections. These components, associated with the offsite SBO recovery path, were grouped into the switchyard SBO recovery path system, created for this purpose, and included in the scoping process. The UFSAR 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 with the exception that some fuse holders were evaluated to confirm that they did not support a system intended function. 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 in Section 2.4.1.37.

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 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.

The SPS 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 the PAMS database 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., compressors, 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 1.7-6). 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. SPS has considered multiple intended functions where applicable, consistent with the staff guidance provided in Table 2.1-3 of NUREG-2192.

Table 2.1.5-1 provides expanded definitions of structure and component passive intended functions identified in this application.

Table 2.1.5-1 Passive Structure and Component Intended Function Definitions

Intended Function Abbreviation	Intended Function
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 database component entry is evaluated with the applicable system. Some equipment not in the PAMS database 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 in a warehouse, or in the Technical Support Center that are staged for use to achieve safe shutdown following a fire. This equipment consists of cabling and cable lugs of various gauges, ventilation ducting (14 inch diameter flexible hose), fuses, air or nitrogen bottles and regulators including blocking devices, and air hoses (for manual operation of air-operated valves). These components are within the scope of subsequent license renewal. Fuses are considered active and are not subject to aging management review. The other equipment is subject to aging management review. The cabling and cable lugs are evaluated with the electrical equipment, the ventilation ducting is evaluated with the ventilation system, and the air bottles, valves, blocking devices 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, SPS routinely conducts tours of the operating spaces. 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 Branch Technical Position APSCB 9.5-1, 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 for subsequent license renewal to address subsequent license renewal Interim Staff Guidance documents (ISG) in the Subsequent License Renewal Applications. Since the issuance of NUREG-2191 and NUREG-2192, there have been no newly issued LR-ISGs that are currently active on the NRC website.

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 to SPS, which does not have 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 (sump screens) are evaluated with the recirculation spray system as described in Section 2.3.2.2. The protective coatings inside containment are evaluated with the Containment Structure 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 to SPS, which 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 at SPS 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 SPS 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 UFSAR 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
Reactor Vessel, Internals, and Reactor Coolant System			
Reactor Vessel	N/A	Yes	Section 2.3.1.1
Reactor Vessel Internals	N/A	Yes	Section 2.3.1.2
Reactor Coolant	RC	Yes	Section 2.3.1.3
Steam Generator	N/A	Yes	Section 2.3.1.4
Engineered Safety Features			
Containment Spray	CS	Yes	Section 2.3.2.1
Recirculation Spray	RS	Yes	Section 2.3.2.2
Residual Heat Removal	RH	Yes	Section 2.3.2.3
Safety Injection	SI	Yes	Section 2.3.2.4
Auxiliary Systems			
Fuel Handling	FH	Yes	Section 2.3.3.1
Fuel Pool Cooling	FC	Yes	Section 2.3.3.2
Cranes and Hoists	CR	Yes	Section 2.3.3.3
Service Water	SW	Yes	Section 2.3.3.4
Circulating Water	CW	Yes	Section 2.3.3.5
Bearing Cooling	BC	Yes	Section 2.3.3.6
Chilled Water	CD	Yes	Section 2.3.3.7
Component Cooling	CC	Yes	Section 2.3.3.8
Neutron Shield Tank Cooling	NS	Yes	Section 2.3.3.9
Primary Grade Water	PG	Yes	Section 2.3.3.10
Instrument Air	IA	Yes	Section 2.3.3.11
Primary and Secondary Plant Gas Supply	GN	Yes	Section 2.3.3.12
Service Air	SA	Yes	Section 2.3.3.13
Boron Recovery	BR	Yes	Section 2.3.3.14

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Chemical and Volume Control	CH	Yes	Section 2.3.3.15
Incore Instrumentation	IC	Yes	Section 2.3.3.16
Reactor Cavity Purification	RL	Yes	Section 2.3.3.17
Sampling System	SS	Yes	Section 2.3.3.18
Decontamination	DC	Yes	Section 2.3.3.19
Drains Aerated	DA	Yes	Section 2.3.3.20
Drains Gaseous	DG	Yes	Section 2.3.3.21
Gaseous Waste	GW	Yes	Section 2.3.3.22
Liquid and Solid Waste	LW	Yes	Section 2.3.3.23
Plumbing	PL	Yes	Section 2.3.3.24
Radiation Monitoring	RM	Yes	Section 2.3.3.25
Vents Aerated	VA	Yes	Section 2.3.3.26
Vents Gaseous	VG	Yes	Section 2.3.3.27
Water Treatment	WT	Yes	Section 2.3.3.28
Ventilation	VS	Yes	Section 2.3.3.29
Leakage Monitoring	LM	Yes	Section 2.3.3.30
Secondary Vents	SV	Yes	Section 2.3.3.31
Vacuum Priming	VP	Yes	Section 2.3.3.32
Containment Vacuum	CV	Yes	Section 2.3.3.33
Fire Protection (includes Radwaste Fire Protection)	FP, RFP	Yes	Section 2.3.3.34
Hydrogen Gas	HG	Yes	Section 2.3.3.35
Emergency Diesel Generator (includes Emergency Electrical Power)	EE, EG	Yes	Section 2.3.3.36
Alternate AC (includes Station Blackout Cooling Water, Station Blackout Fuel Oil, Station Blackout Lube Oil, and Station Blackout Start Air)	AAC, BCW, BFO, BLO, BSA	Yes	Section 2.3.3.37

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Security	SE	Yes	Section 2.3.3.38
Buildings and Structures	BS	Yes	Section 2.3.3.39
Containment Access	CA	Yes	Section 2.3.3.40
Electrical Power	EP	Yes	Section 2.3.3.41
Helium Vacuum Drying	HVD	Yes	Section 2.3.3.42
Reactor Building Penetrations	PEN	Yes	Section 2.3.3.43
Beyond Design Basis	BDB	No	UFSAR 6.2.2.1.4, 6.3.1.3.4, 7.7.1, 9.1.2.1, 9.10.2.6, 10.3.1.2, 10.3.5.2
Compressed Oxygen Containment Self-Contained Breathing Apparatus	OX	No	UFSAR 9.10.2.3.3
Fish Screens	FS	No	UFSAR 9.9.2, 10.3.4
Rad Waste Facility Heating	RHV	No	UFSAR 11.2.2
Rad Waste Facility Liquid Waste	RLW	No	UFSAR 11.2
Rad Waste Radiation Monitoring	RRM	No	UFSAR 11.2.2
Rad Waste Domestic Water	RDW	No	N/A
Sewage Treatment	ST	No	N/A
Station Blackout Service Air	BSR	No	N/A
Temporary Service Air	TSA	No	N/A
Used Oil	UO	No	N/A
Steam and Power Conversion Systems			
Main Turbine	TM	Yes	Section 2.3.4.1
Electro-Hydraulic Control	EH	Yes	Section 2.3.4.2
Lubricating Oil	LO	Yes	Section 2.3.4.2
Main Steam	MS	Yes	Section 2.3.4.4
Heating	HS	Yes	Section 2.3.4.5
Extraction Steam	ES	Yes	Section 2.3.4.6

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Auxiliary Steam	AS	Yes	Section 2.3.4.7
Feedwater	FW	Yes	Section 2.3.4.8
Condensate	CN	Yes	Section 2.3.4.9
Condensate Polishing	CP	Yes	Section 2.3.4.10
Steam Drains	SD	Yes	Section 2.3.4.11
Blowdown	BD	Yes	Section 2.3.4.12
Steam Generator Recirculation and Transfer	RT	Yes	Section 2.3.4.13
Containments, Structures, and Component Supports			
Containment		Yes	Section 2.4.1.1
Auxiliary Building Structure includes: Cable Vaults Cable Tunnels Pipe Tunnels Upper Cable Vault Motor Control Center Rooms		Yes	Section 2.4.1.2
Discharge Canal		Yes	Section 2.4.1.3
Intake Canal		Yes	Section 2.4.1.4
Fuel Building Structure includes: Boron Recovery Pump House Decontamination Building Health Physics Yard Office Building		Yes	Section 2.4.1.5
Discharge Tunnel and Seal Pit		Yes	Section 2.4.1.6
High Level Intake Structure		Yes	Section 2.4.1.7
Low-Level Intake Structure		Yes	Section 2.4.1.8
Black Battery Building		Yes	Section 2.4.1.9
Central Alarm Station		Yes	Section 2.4.1.10
Condensate Polishing Building		Yes	Section 2.4.1.11
Laundry Facility		Yes	Section 2.4.1.12
Machine Shop		Yes	Section 2.4.1.13
Radwaste Facility		Yes	Section 2.4.1.14

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
SBO Building		Yes	Section 2.4.1.15
Service Building		Yes	Section 2.4.1.16
Turbine Building		Yes	Section 2.4.1.17
Containment Spray Pump Building		Yes	Section 2.4.1.18
Fire Pump House		Yes	Section 2.4.1.19
Fuel Oil Pump House		Yes	Section 2.4.1.20
Main Steam Valve House		Yes	Section 2.4.1.21
Safeguards Building		Yes	Section 2.4.1.22
Buried Fuel Oil Tank Missile Barrier		Yes	Section 2.4.1.23
Chemical Addition Tank Foundation		Yes	Section 2.4.1.24
Duct Banks		Yes	Section 2.4.1.25
Emergency Condensate Tank Foundations and Missile Barriers		Yes	Section 2.4.1.26
Fire Protection/Domestic Water Tank Foundation		Yes	Section 2.4.1.27
Fuel Oil Line Missile Barrier		Yes	Section 2.4.1.28
Fuel Oil Storage Tank Dike		Yes	Section 2.4.1.29
Manholes		Yes	Section 2.4.1.30
Reactor Containment Subsurface Drainage System Access Shaft		Yes	Section 2.4.1.31
Refueling Water Storage Tank Foundation		Yes	Section 2.4.1.32
SBO Structures for Offsite Power includes: 230 kV and 500 kV Switchyard Control Houses Reserve Station Service Transformer Structure Power Poles and Foundations		Yes	Section 2.4.1.33
Security Lighting Poles		Yes	Section 2.4.1.34
Transformer Firewalls and Dikes		Yes	Section 2.4.1.35
Component Supports		Yes	Section 2.4.1.36
Miscellaneous Structural Commodities		Yes	Section 2.4.1.37

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
NSSS Supports		Yes	Section 2.4.1.38
Administration Building		No	N/A
Boron Recovery Tank Building including the tank dikes		No	N/A
Compressed gas storage pad		No	N/A
Dredge Spoils Pond		No	N/A
Environmental Building		No	N/A
Gravel Neck Combustion Turbine Facility		No	N/A
Independent Spent Fuel Storage Installation (ISFSI)		No	N/A
Information Center		No	N/A
Intake Vacuum Priming Pump House		No	N/A
ISFSI Low Level Radwaste Storage Building		No	N/A
Loading Dock at the Low Level Intake Structure		No	N/A
Miscellaneous Concrete Storage Pads		No	N/A
Office Building (West of Turbine Building)		No	N/A
Old Steam Generator Storage Facility		No	N/A
Pipe Refurbishment Building		No	N/A
Primary Grade Water Tank Foundation		No	N/A
Security Buildings		No	N/A
Sewage Treatment Plant		No	N/A
South Annex Maintenance Building		No	N/A
South Annex Records Building		No	N/A
Switchyard Microwave Tower		No	N/A
Training Building		No	N/A
Transmission Line Attachments to the Turbine Building		No	N/A
Transmission Line Towers		No	N/A

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Vacuum Priming Houses #1 and #21		No	N/A
Warehouses, Various Shops and Office Buildings Outside the Protected Area		No	N/A
Weather Towers		No	N/A
Beyond Design Basis Storage Building		No	N/A
Electrical and I&C Systems			
Ambient Temperature Monitoring	AM	Yes	N/A
ATWS Mitigation system	AMS	Yes	UFSAR Section 7.2.3.2.7
Consequence Limiting Safeguards	CLS	Yes	UFSAR Section 7.5.1.2
Computer	CM	Yes	UFSAR Section 7.8
Communications	CO	Yes	UFSAR Section 9.10.2.6
Emergency Lighting	ELT	Yes	UFSAR Sections 8.4.5, 9.10.2.5
DC Power	EPD	Yes	UFSAR Sections 8.4.4, 8.4.5
Emergency Response Capability	ERC	Yes	UFSAR Section 7.9
Heat Tracing	HT	Yes	UFSAR Section 8.5
Nuclear Instrumentation	NI	Yes	UFSAR Section 7.4
Process Instrumentation	PRO	Yes	UFSAR Section 7
Rod Control	RD	Yes	UFSAR Sections 7.3.2, 7.3.3
Reactor Protection	RP	Yes	UFSAR Section 7.2

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Recirculation Mode Transfer	RMT	Yes	UFSAR Section 7.5.2
Switchyard SBO Recovery Path (SWYD)	N/A	Yes	N/A
Valve Monitoring System	VMS	Yes	N/A
Earthquake Reporting	ER	No	UFSAR 2.5.4.3
Early Warning	EW	No	N/A
Generic EQML Components	GEC	No	N/A
Loose Parts Monitoring	LPM	No	UFSAR 4.2.10
Meteorological Monitoring	MM	No	UFSAR 2.2.1
Reactor Instrumentation	RI	No	N/A
Seismic Instrumentation	SM	No	N/A

Intentionally Blank

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 Unit 1 and 2 reactor vessels are categorized as standard Westinghouse 157-inch inside diameter three-loop reactor vessels. Each reactor vessel is a cylindrical shell with a welded, hemispherical lower head and a flanged hemispherical upper head. The reactor vessel provides structural support for the reactor core and a pressure boundary for the reactor coolant in which the core is submerged. The reactor vessel shell is constructed of plate segments welded together both circumferentially and longitudinally.

The reactor vessel is vertically mounted on welded support pads attached to the bottom of the primary nozzles, which are spaced circumferentially around the vessel just below the vessel flange. The hot-leg and cold-leg reactor coolant loop piping for each of the three loops is welded to the primary nozzles. The internal surfaces of the vessel in contact with borated reactor coolant are clad with a stainless steel overlay, which provides corrosion resistance. The lower head has penetrations (instrumentation tubes), for movable in-core nuclear flux thimble tubes, which extend into the reactor vessel interior and mate with the lower internals assembly. The core support ledge, located inside the vessel just below the vessel flange, supports the weight of the reactor vessel internals and the fuel. The lower internals assembly hangs from the core support ledge and is provided with lateral support by core support lugs.

The vessel flange and the closure head flange are joined by 58 6-inch closure studs, nuts, and spherical washers. Two concentric, hollow, metallic o-rings between the closure head flange and the vessel flange form an inner and outer seal. A dynamic seal is formed when the closure head is bolted in place and by the internal pressure in the reactor vessel.

The reactor vessel closure head dome is penetrated by the control rod drive mechanism housing tubes and a vent pipe. Nozzle support pads located below the primary nozzles provide an interface for support of the vessel. The weight of the vessel is transmitted through the nozzle support pads to the neutron shield tank that surrounds the vessel.

SPS Unit 1 and 2 reactor vessel heads were replaced in 2003. The replacement reactor vessel heads have penetrations and connecting welds fabricated using Alloy 690 material that is more resistant to primary water stress corrosion cracking than the Alloy 600 material used in the fabrication of the original heads.

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 adapter plugs, instrumentation tubes, the reactor vessel head, closure stud assemblies, lifting lugs, and seal table components. The head flange o-rings are periodically replaced, and therefore, not subject to aging management review.

System Intended Functions

Portions of the reactor vessel perform the following safety-related functions: The reactor vessel maintains the reactor coolant system pressure boundary and provides fission product boundaries, 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).

Portions of the reactor vessel are 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).

UFSAR References

Additional details of the reactor vessel can be found in the UFSAR, Section 3.5, Section 4.2.2.1, Section 4.3.3.2, Section 14.5.1, Section 14.5.2, and Section 14.5.3.

Subsequent License Renewal Boundary Drawings

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

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 reactor vessel internals are designed to direct coolant flow, support the reactor core, and guide the control rod assemblies in the withdrawn position.

The reactor internals consist of two basic assemblies: an upper internals assembly that is removed during each refueling operation to obtain access to the reactor core, and a lower internals assembly, which includes the core barrel and baffle/former assembly that can be removed, if desired, following a complete core unload.

The fact that all of the internals can be removed from the reactor vessel provides the capability to perform periodic inspections to determine the condition of the internals or to effect repairs, if needed. This unique characteristic of all Westinghouse internals provides a means to determine the reactor internals functionality during the subsequent period of extended operation.

The lower internals assembly is supported in the vessel by clamping to a ledge below the vessel-head mating surface and closely guided at the bottom by radial support/clevis assemblies. The core support ledge supports the entire weight of the reactor vessel internals and the fuel. The lower internals assembly hangs from the ledge. A circumferential spring rests on top of the lower internal flange, which rests on the ledge. A diffuser plate is also provided to enhance flow uniformity entering the lower core plate.

The upper internals assembly sits on the spring. The spring is compressed when the vessel head is lowered and tightened down, holding the lower internals assembly against the core support ledge and the upper internals assembly against the vessel head. This minimizes flow-induced vibrations and prevents upward motion of the lower internals assembly. The bottom of the upper internals assembly is closely guided by the core plate alignment pins.

System Evaluation Boundary

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

System Intended Functions

Portions of the reactor vessel internals perform the following safety-related functions: The reactor vessel internals support and orient the fuel assemblies and control rod assemblies, direct the coolant flow to and from the core components, and support and guide the incore instrumentation. Also, the reactor vessel internals provide a secondary support structure for limiting the core support structure downward displacement. In addition, the reactor vessel internals provide gamma and neutron shielding for the reactor vessel. Therefore, the reactor vessel internals are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the reactor vessel internals can be found in the UFSAR, Section 3.5.1, Section 14.5.3, Figure 3.5-2, Figure 3.5-6, and Figure 3.5-7.

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 transfers heat produced in the reactor core to the steam generators, where steam is generated to drive the turbine generator. Reactor coolant is circulated through the core at a flow rate and temperature consistent with achieving the desired reactor core thermal-hydraulic performance. The reactor coolant also acts as a neutron moderator, a reflector, and a solvent for the neutron absorber.

The reactor coolant system consists of three piping loops (A, B, and C) interconnected at the reactor vessel. Each loop consists of one reactor coolant pump, one steam generator, valves, and interconnecting piping. The pressurizer, connected to loop C hot leg, provides a means for controlling reactor coolant system pressure. The pressurizer also provides overpressure protection for the reactor coolant system. Two power-operated relief valves and three safety valves automatically open during an overpressure condition, and relieve steam to the pressurizer relief tank, where the steam is condensed and cooled. The reactor coolant system also contains piping and components that allow filling, draining, sampling and venting of specific reactor coolant system components.

During operation, the reactor coolant system heat capacity attenuates thermal transients. Reactor coolant system piping is used by the safety injection system to deliver cooling water to the core for emergency cooling and shutdown during a loss-of-coolant accident.

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 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 or provide structural support of reactor coolant pressure boundary components and is therefore excluded from scope. 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 reactor coolant system includes a neutron shield tank located inside the primary shield wall around the reactor vessel. The tank provides support for the reactor vessel as described in the structural section of the application, but aging management of the neutron shield tank is addressed in this section (mechanical section) of the application.

System Intended Functions

Portions of the reactor coolant system perform the following safety-related functions: The reactor coolant system provides a pressure boundary for the reactor coolant and removes core decay, latent and reactor coolant pump heat during normal operations, shutdown and following a design basis event. The system mitigates the consequence of a design basis event, controls core reactivity during normal operations, shutdown and following a design basis event. The system also provides safety-related indication and provides containment isolation function. Therefore, the reactor coolant system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the reactor coolant system contain 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.

Portions of the reactor coolant system are 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).

UFSAR References

Additional details of the reactor coolant system can be found in the UFSAR, Section 3.2.2.3, Section 3.2.2.4, Section 4.1.2, Section 4.2, Section 7.1.2, Section 7.5.3.5, Section 14.5.1, Section 14.5.2, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-072A Sht 2

11448-SLRM-072A Sht 3

11448-SLRM-072A Sht 4

11448-SLRM-072E Sht 2

11448-SLRM-086A Sht 1

11448-SLRM-086A Sht 2

11448-SLRM-086A Sht 3

11448-SLRM-086B Sht 1

11448-SLRM-086B Sht 2

11448-SLRM-086B Sht 3

11448-SLRM-086C Sht 1

11448-SLRM-086C Sht 2

11548-SLRM-072A Sht 2

11548-SLRM-072A Sht 3

11548-SLRM-072A Sht 4

11548-SLRM-072B Sht 3

11548-SLRM-086A Sht 1

11548-SLRM-086A Sht 2

11548-SLRM-086A Sht 3

11548-SLRM-086B Sht 1

11548-SLRM-086B Sht 2

11548-SLRM-086B Sht 3

11548-SLRM-086C Sht 1

11548-SLRM-086C Sht 2

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 Generator

System Description

Three steam generators are installed in each unit with one steam generator installed in each of the three reactor coolant loops. The steam generators are vertical, shell and U-tube heat exchangers with integral moisture-separating equipment. The steam generators function to transfer heat from the single-phase, high-pressure, high-temperature borated reactor coolant on the primary side of the tubes to the two-phase steam-water mixture on the secondary side of the tubes. The internal surfaces of the steam generator in contact with borated reactor coolant are clad with a stainless steel weld overlay, except for the tubesheet, which is clad with nickel alloy, for corrosion resistance.

The steam generator is a recirculating design and consists of a primary (tube) side and a secondary (shell) side. Reactor coolant flows through the primary side through inverted U-tubes, entering and leaving through the primary nozzles located in the hemispherical bottom chamber (channel head). The channel head is welded to a plate (tubesheet) from which the tube bundle extends. The channel head is divided into inlet and outlet chambers by a vertical divider plate extending from the channel head to the tubesheet. Manways are provided for access to both sides of the divided channel head. Pressure boundary integrity is maintained by manway covers that are bolted to the manways.

On the secondary side, tube support plates, stay rods, stay rod spacer pipes, and anti-vibration bars are provided for structural support of the U-tubes. The tube support plate closest to the tubesheet is identified as the flow distribution baffle.

The steam generator tube bundle is contained inside a cylindrical wrapper. The space between the wrapper and the inside of the steam generator shell forms an annular region called the downcomer. Feedwater enters the steam generator through the feedwater inlet nozzle located in the upper shell and is distributed around the periphery of the steam generator by an internal feedwater distribution ring (feed ring). The feedwater exits the top of the feed ring through J-nozzles, where it mixes with recirculated water from the moisture separators and flows down the downcomer. The mixture of subcooled feedwater and saturated recirculated water exits the downcomer's annular region at the tubesheet, where it flows under the wrapper and is distributed across the tubesheet. The mixture is heated to boiling by reactor coolant heat transferred through the U-tubes. The saturated steam/water mixture enters the moisture separator section, where liquid is removed from the mixture and returned to the evaporator section. Essentially dry steam exiting the moisture separator section is conducted through the steam outlet nozzle that is fitted with a flow-limiting device designed to limit steam flow in the event of a main steam pipe rupture.

Secondary side penetrations (handholes, access ports, blowdown nozzles, instrument taps, and manways) are provided for instrumentation, maintenance, and inspection activities.

A nozzle in the upper shell facilitates the maintenance of wet layup chemistry conditions in the steam generator during shutdown periods via the steam generator recirculation and transfer system.

System Evaluation Boundary

The evaluation boundary for the steam generator components subject to aging management review includes the subcomponents that provide pressure integrity, structural support, flow distribution, and steam flow restriction. The blowdown system nickel alloy piping within the steam generators is evaluated with the blowdown system.

System Intended Functions

Portions of 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).

Portions of 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).

UFSAR References

Additional details of the steam generator can be found in the UFSAR, Section 4.1.2.5, Section 4.1.2.7, Section 4.2.2.3, Section 10.3.1.2, Section 14.3.2, Section 14.5.1, Section 14.5.2, Section 10.3-2, and Section 10.3-3.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the steam generator.

Components Subject to Aging Management Review

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

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 Generator - 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 and ring (and cladding)	Pressure Boundary
Bottom mounted instrumentation guide tube	Pressure Boundary
Closure head dome and flange (and cladding)	Pressure Boundary
Closure stud, nut, and washer	Pressure Boundary
Control rod drive mechanism (head adapter plug)	Pressure Boundary
Control rod drive mechanism (housing flange)	Pressure Boundary
Control rod drive mechanism (housing tube)	Pressure Boundary
Control rod drive mechanism (latch housing)	Pressure Boundary
Control rod drive mechanism (rod travel housing)	Pressure Boundary
Core support lug	Structural Support
Head vent pipe	Pressure Boundary
Instrumentation port assembly	Pressure Boundary
Instrumentation tube	Pressure Boundary
Instrumentation tube safe end	Pressure Boundary
Lifting lug	Structural Support
Primary nozzle and support pad (and cladding)	Pressure Boundary, Structural Support

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.1-1 Reactor Vessel

Subcomponent	Intended Function(s)
Primary nozzle safe end	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 (and cladding)	Pressure Boundary, Structural Support
Vessel flange leakage monitor line	Pressure Boundary
Vessel shell (upper, intermediate, lower and cladding)	Pressure Boundary

The AMR 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 2.1.5-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
Alignment and interfacing (clevis insert bolt)	Structural Support
Alignment and interfacing (clevis insert dowel)	Structural Support
Alignment and interfacing (clevis insert wear surface)	Structural Support
Alignment and interfacing (internals hold-down spring)	Structural Support
Alignment and interfacing (radial support key wear surface)	Structural Support
Alignment and interfacing (thermal sleeve)	Structural Support
Alignment and interfacing (upper core plate alignment pin wear surface)	Structural Support
Alignment and interfacing (upper core plate alignment pin)	Structural Support
Baffle former (baffle edge bolt)	Structural Support
Baffle former (baffle former bolt)	Structural Support
Baffle former (baffle plate)	Flow Distribution, Structural Support
Baffle former (corner bolt)	Structural Support
Bottom mounted instrumentation (column body)	Structural Support
Bottom mounted instrumentation (flux thimble tube)	Structural Support
Control rod guide tube (guide plate)	Structural Support
Control rod guide tube (guide tube support pin nut) (Unit 1 only)	Structural Support
Control rod guide tube (guide tube support pin) (Unit 1 only)	Structural Support

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
Control rod guide tube (lower flange)	Structural Support
Core barrel (barrel former bolt)	Structural Support
Core barrel (core barrel flange)	Flow Distribution, Structural Support
Core barrel (core barrel outlet nozzle)	Structural Support
Core barrel (lower axial weld)	Structural Support
Core barrel (lower flange weld)	Structural Support
Core barrel (lower girth weld)	Structural Support
Core barrel (upper axial weld)	Structural Support
Core barrel (upper flange weld)	Structural Support
Core barrel (upper girth weld)	Structural Support
Lower internals (fuel alignment pin)	Structural Support
Lower internals (lower core plate)	Flow Distribution, Structural Support
Lower support (column body)	Structural Support
Lower support (column bolt)	Structural Support
Lower support (lower support forging)	Structural Support
No additional measures components	Flow Distribution, Structural Support
Thermal shield (flexure)	Structural Support
Upper internals (fuel alignment pin)	Structural Support
Upper internals (upper core plate)	Structural Support
Upper internals (upper support ring)	Structural Support

See Table 2.1.5-1 for definitions of intended functions.

The AMR 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 2.1.5-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Flexible hose	Pressure Boundary
Heat exchanger (reactor coolant pump motor lower bearing oil cooler - coiled tube inside the reservoir)	Pressure Boundary
Heat exchanger (reactor coolant pump motor lower bearing oil cooler - coiled tube outside the reservoir)	Pressure Boundary
Heat exchanger (reactor coolant pump motor stator cooler - fin and tube)	Heat Transfer, Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil cooler - channel head)	Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil cooler - shell)	Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil cooler - tubes)	Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil cooler - tubesheet)	Pressure Boundary
Hydraulic isolator	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pressurizer (heater well and heater sheath)	Pressure Boundary
Pressurizer (instrument nozzles)	Pressure Boundary

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Pressurizer (lower head and cladding)	Pressure Boundary
Pressurizer (manway - includes pad and cladding)	Pressure Boundary
Pressurizer (manway cover and insert)	Pressure Boundary
Pressurizer (manway cover bolting)	Pressure Boundary
Pressurizer (relief nozzle and cladding)	Pressure Boundary
Pressurizer (relief nozzle safe end)	Pressure Boundary
Pressurizer (safety nozzle and cladding)	Pressure Boundary
Pressurizer (safety nozzle safe end)	Pressure Boundary
Pressurizer (sample line nozzle)	Pressure Boundary
Pressurizer (seismic support lugs)	Structural Support
Pressurizer (shell and cladding)	Pressure Boundary
Pressurizer (spray nozzle and cladding)	Pressure Boundary
Pressurizer (spray nozzle safe end)	Pressure Boundary
Pressurizer (spray nozzle thermal sleeve)	Limit Thermal Cycling
Pressurizer (support skirt and flange)	Structural Support
Pressurizer (surge nozzle and cladding)	Pressure Boundary
Pressurizer (surge nozzle safe end)	Pressure Boundary
Pressurizer (surge nozzle thermal sleeve)	Limit Thermal Cycling
Pressurizer (upper head and cladding)	Pressure Boundary

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Pump casing (reactor coolant)	Pressure Boundary
Tank (neutron shield)	Pressure Boundary, Structural Support
Tank (pressurizer relief)	Leakage Boundary (Spatial)
Thermal insulation	Thermal insulation
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR 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 2.1.5-1 for definitions of intended functions.

Table 2.3.1-4 Steam Generator

Subcomponent	Intended Function(s)
Anti-vibration bar	Structural Support
Channel head (and cladding)	Pressure Boundary
Channel head divider plate	Flow Distribution
Feedwater inlet nozzle	Pressure Boundary
Feedwater inlet nozzle thermal sleeve	Limit Thermal Cycling
Feedwater inlet ring	Flow Distribution
Feedwater inlet ring J nozzle	Flow Distribution
Moisture separator assembly	Flow Distribution
Primary inlet nozzle and outlet nozzle (and cladding)	Pressure Boundary
Primary inlet nozzle safe end and outlet nozzle safe end	Pressure Boundary
Primary manway (includes pad and cladding)	Pressure Boundary
Primary manway cover and insert	Pressure Boundary
Primary manway cover bolt	Pressure Boundary
Secondary closure cover	Pressure Boundary
Secondary closure cover bolt	Pressure Boundary
Secondary manway (includes pad)	Pressure Boundary
Secondary side shell (head, upper shell, lower shell, transition cone, girth weld)	Pressure Boundary
Secondary side shell penetration	Pressure Boundary

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.1-4 Steam Generator

Subcomponent	Intended Function(s)
Stay rod	Structural Support
Steam flow limiter	Restricts Flow
Steam outlet nozzle	Pressure Boundary
Support pad	Structural Support
Tube bundle wrapper	Structural Support
Tube plug	Pressure Boundary
Tube support plate	Structural Support
Tubesheet (and cladding)	Pressure Boundary
U-tube	Heat Transfer, Pressure Boundary

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

2.3.2 ENGINEERED SAFETY FEATURES

2.3.2.1 Containment Spray

System Description

The containment spray system pumps cool, borated water from the refueling water storage tank, mixed with a sodium hydroxide solution from the chemical addition tank, through spray ring headers and nozzles into the Containment. The spray solution absorbs heat from the containment atmosphere to reduce pressure and prevent challenging the structural integrity of the Containment. In addition, the spray reduces the airborne iodine concentration in the post-accident containment atmosphere to maintain accident dose within limits. The refueling water storage tank also provides the source of water to the safety injection system for the injection phase of design basis accident mitigation.

System Evaluation Boundary

The evaluation boundary for the containment spray system components subject to aging management review includes the chemical addition tank and pump, the refueling water storage tank and the attached piping through the containment spray pumps to the containment spray headers and associated branch piping, and nonsafety-related piping and components that provide a leakage boundary or structural integrity function. The foundations for the refueling water storage tank and chemical addition tank are addressed in the structural section of this application.

System Intended Functions

Portions of the containment spray system perform the following safety-related functions: The system is relied upon to cool and depressurize the Containment and remove radioactive iodine from the containment atmosphere following a design basis event. The system delivers cool water to the containment sump to ensure adequate net positive suction head for outside recirculation spray pump operation. The system also performs a containment isolation function, and includes safety-related indications. Therefore, the containment spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the containment spray system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the containment 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.

Portions of the containment spray system are 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 containment spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the containment spray system can be found in the UFSAR, Section 6.3.1, Table 5.2-1, Table 5.2-2, and Table 6.2-12 Note b.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-084A Sht 1

11448-SLRM-084A Sht 2

11448-SLRM-084A Sht 3

11548-SLRM-084A Sht 1

11548-SLRM-084A Sht 2

11548-SLRM-084A Sht 3

Components Subject to Aging Management Review

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

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

2.3.2.2 Recirculation Spray

System Description

The recirculation spray system provides long-term heat removal from the containment atmosphere and core cooling water following a design basis loss-of-coolant accident. The recirculation spray system transfers heat from the reactor core, via coolant spilled from the piping break, and from the containment atmosphere to the service water system through the recirculation spray heat exchangers. Water collected in the containment sump is pumped through the heat exchangers, then through spray ring headers and nozzles, into the containment atmosphere. The recirculation spray system is designed to return the post-accident containment atmosphere to subatmospheric pressure and to maintain subatmospheric conditions for the duration of the accident recovery, thus preventing outleakage of fission products. The cooled water in the containment sump is pumped back through the reactor core by the safety injection system.

System Evaluation Boundary

The evaluation boundary for the recirculation spray system components subject to aging management review includes the containment sump strainer (screens), the flowpath through the recirculation spray pumps to the spray rings, and the attached branch piping and nonsafety-related components that perform a leakage boundary or structural integrity function.

System Intended Functions

Portions of the recirculation spray system perform the following safety-related functions: The system, in conjunction with the containment spray system, depressurizes the Containment and removes radioactive iodine following a design basis accident, provides containment isolation, provides long term core cooling following a design basis accident, and provides safety-related indication. Therefore, the recirculation spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the recirculation spray system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the recirculation 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.

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

UFSAR References

Additional details of the recirculation spray system can be found in the UFSAR, Section 6.3.1, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-084A Sht 2

11448-SLRM-084B Sht 1

11448-SLRM-084B Sht 2

11548-SLRM-084B Sht 1

11548-SLRM-084B Sht 2

Components Subject to Aging Management Review

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

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

2.3.2.3 Residual Heat Removal

System Description

The residual heat removal system transfers heat from the reactor coolant system to the component cooling system when the reactor coolant system is less than 350°F and 450 psig. The system consists of two pumps and two heat exchangers, with isolation valves to separate the system from the reactor coolant system when at normal operating pressure. When in service, the system normally operates with one pump and one heat exchanger in service. Reactor coolant is drawn from the “A” loop hot leg, pumped through the residual heat removal system heat exchangers, and returned to the reactor coolant system via the “B” and “C” loop cold legs to control primary system temperature. The residual heat removal system also provides the capability to pump the reactor cavity water back to the refueling water storage tank following refueling operations.

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 and back to the reactor coolant system via the safety injection accumulator discharge lines, the branch lines to other systems, and nonsafety-related components with a leakage boundary or structural integrity function.

System Intended Functions

Portions of the residual heat removal system perform the following safety-related functions: The system removes heat from the reactor coolant system, mixes reactor coolant to ensure uniform boron concentration, provides a safety-related 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).

Portions of the residual heat removal system contain 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.

Portions of the residual heat removal system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). 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).

UFSAR References

Additional details of the residual heat removal system can be found in the UFSAR, Section 9.3, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-087A Sht 1

11448-SLRM-087A Sht 2

11548-SLRM-087A Sht 1

11548-SLRM-087A Sht 2

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 provides emergency cooling to the reactor core and to provide adequate shutdown margin in the event of a loss-of-coolant accident or steam line break. The safety injection system includes three high-head injection pumps, two low-head injection pumps, and three hydro-pneumatic accumulator tanks at each unit that provide injection of borated water into the reactor coolant system. The pumps also provide the capability to remove reactor core decay heat for extended periods following an accident. This is accomplished by recirculating coolant, cooled by the recirculation spray system, from the containment sump through the core.

System Evaluation Boundary

The evaluation boundary for the safety injection system components that are subject to aging management review includes the safety-related flowpaths through the low-head safety injection pumps to the reactor coolant system, the suction flowpaths to the charging pumps from the refueling water storage tank and from the low-head safety injection pumps, the flowpaths from the charging pumps to the reactor coolant system, and the accumulators, the accumulator fill, drain and test lines, and their discharge flowpaths to the reactor coolant system. Additionally, nonsafety-related fluid filled piping, and nonsafety-related piping directly attached to safety-related piping is subject to aging management review.

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 screens/strainers associated with the containment sump that supply suction to the low-head safety injection pumps are evaluated with the recirculation spray system.

System Intended Functions

Portions of the safety injection system perform the following safety-related functions: The system provides cool borated water to the reactor coolant system following a design basis event to mitigate fuel cladding damage and to maintain the reactor shutdown, provides safety-related indication and provides containment isolation. Therefore, the safety injection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the safety injection system contain 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.

Portions of the safety injection system are 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 safety injection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the safety injection system can be found in the UFSAR, Section 6.2, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-089A Sht 1

11448-SLRM-089A Sht 2

11448-SLRM-089A Sht 3

11448-SLRM-089B Sht 1

11448-SLRM-089B Sht 2

11448-SLRM-089B Sht 3

11448-SLRM-089B Sht 4

11548-SLRM-089A Sht 1

11548-SLRM-089A Sht 2

11548-SLRM-089A Sht 3

11548-SLRM-089B Sht 1

11548-SLRM-089B Sht 2

11548-SLRM-089B Sht 3

11548-SLRM-089B Sht 4

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.

Intentionally Blank

Screening Results Tables: Engineered Safety Features Systems

Table 2.3.2-1 Containment Spray

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Filter element	Filtration
Filter housing	Pressure Boundary
Flow element	Structural Integrity (Attached)
Heat exchanger (refueling water refrigeration unit - shell)	Structural Integrity (Attached)
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (chemical addition)	Pressure Boundary
Pump casing (containment spray)	Pressure Boundary
Pump casing (refueling water recirculation)	Leakage Boundary (Spatial)
Sample sink	Leakage Boundary (Spatial)
Spray nozzle	Spray Pattern
Strainer body	Pressure Boundary
Tank (chemical addition)	Pressure Boundary
Tank (refueling water storage)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.2.2-1 Engineering Safety Features - Containment Spray - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.2-2 Recirculation Spray

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Pressure Boundary
Flow element	Pressure Boundary, Restricts Flow
Heat exchanger (recirculation spray cooler - channel)	Pressure Boundary
Heat exchanger (recirculation spray cooler - shell)	Pressure Boundary
Heat exchanger (recirculation spray cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (recirculation spray cooler - tubesheet)	Pressure Boundary
Heat exchanger (seal cooler - tube)	Heat Transfer, Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (recirculation spray)	Pressure Boundary
Spray nozzle	Spray Pattern
Sump screen	Filtration
Tank (seal accumulator)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.2.2-2 Engineering Safety Features - Recirculation Spray - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.2-3 Residual Heat Removal

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

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

See Table 2.1.5-1 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)
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Heat exchanger (seal cooler - tube)	Heat Transfer, Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (hydro test)	Leakage Boundary (Spatial)
Pump casing (low-head)	Pressure Boundary
Tank (accumulator)	Pressure Boundary
Tank (low-head pump seal accumulator)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

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

See Table 2.1.5-1 for definitions of intended functions.

Intentionally Blank

2.3.3 AUXILIARY SYSTEMS

2.3.3.1 Fuel Handling

System Description

The fuel handling system provides for safe handling of new and spent fuel assemblies during refueling operations and postulated accidents. The system includes cranes, hoists and other fuel handling equipment, as well as the fuel transfer tube and gate valve. The system also encompasses equipment utilized to support independent spent fuel storage installation operations regulated by 10 CFR 72.

System Evaluation Boundary

The evaluation boundary for the fuel handling system components subject to aging management review includes the fuel transfer tube assemblies and gate valves. Cranes and hoists within the scope of subsequent license renewal are addressed in the cranes and hoists system.

System Intended Functions

Portions of the fuel handling system perform the following safety-related function: The system provides containment isolation and provides a pressure boundary for the spent fuel pool. Therefore, the fuel handling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the fuel handling system can be found in the UFSAR, Section 5.2.2, Section 9.12, Section 15.5.1.8, and Figure 15.5-10.

Subsequent License Renewal Boundary Drawings

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

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-1, Fuel Handling.

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

2.3.3.2 Fuel Pool Cooling

System Description

The fuel pool cooling system transfers heat from the spent fuel pool to the component cooling system. The system also provides a means for water chemistry control for the spent fuel pool. The fuel pool cooling system recirculates borated water from the spent fuel pool through the fuel pool cooling heat exchangers and back to the pool. The fuel pool cooling pump suction connection to the spent fuel pool is at an elevation that prevents draining the pool below the limiting water level in the event of a leak in the fuel pool cooling system. A bypass purification loop provides the capability to filter and demineralize the spent fuel pool water.

System Evaluation Boundary

The evaluation boundary for the fuel pool cooling system components subject to aging management review includes the nonsafety-related 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, as well as nonsafety-related pumps, filters, demineralizer and piping components that retain water in buildings containing safety-related components. The spent fuel pool skimmers and attached flexible hoses are not within-scope because their pressure boundaries are submerged, and are either at ambient pressure or below, such that loss of integrity could not result in external leakage that could result in loss of a safety-related function. There are no passive safety-related mechanical components within the system. The fuel pool liner and storage racks are evaluated in the structural section of the SLRA.

System Intended Functions

Portions of the fuel pool cooling system perform the following safety-related functions: The system contains safety-related electrical components that supply power to the fuel pool cooling pumps. Therefore, the fuel pool cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1). However, no mechanical components are safety-related.

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

UFSAR References

Additional details of the fuel pool cooling system can be found in the UFSAR, Section 9.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the fuel pool cooling system is listed below:

11448-SLRM-081A Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-2, Fuel Pool Cooling.

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

2.3.3.3 Cranes and Hoists

System Description

The cranes and hoists system is comprised of load handling cranes, hoists and lifting devices. Included in the evaluation boundary of the cranes and hoists system is load handling equipment in various areas of the facility. The following cranes and hoists that are within the scope of NUREG-0612 are within-scope for subsequent license renewal.

- Auxiliary Building Structure 10-ton monorail
- Auxiliary Building Structure 5-ton monorail
- Containment annulus monorails
- Containment jib cranes
- Containment polar cranes
- Fuel Building Structure motor driven platform (also called the fuel handling bridge crane)
- Residual heat removal pump motor lifting lug (lugs mounted in Containment to support chain hoist)
- Spent fuel crane

Other cranes and hoists that are not within the scope of NUREG-0612, but are used to lift 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:

- New fuel transfer elevator
- Refueling manipulator cranes

In addition to the cranes and hoists listed above, the following lifting devices are within the scope of NUREG-0612 and are within the scope of subsequent license renewal:

- Long cask lid lifting tool
- Reactor coolant pump motor sling
- Reactor vessel head lifting device
- Reactor vessel head stud racks
- Reactor vessel internals lifting rig
- Short cask lid lifting tool
- Spent filter cask spreader beam
- Spent fuel cask lifting yoke
- Spent fuel pool transfer canal gates alternate lift rig

System Evaluation Boundary

The evaluation boundary for the cranes and hoists system components subject to aging management review includes load-bearing elements that support the load in a passive manner. This includes the structural bolting, beams, girders, plates, rails and retaining clips associated with the new fuel elevator, the cranes and hoists listed above, as well as the passive lifting devices listed above.

System Intended Functions

Portions of the cranes and hoists system perform the following safety-related functions: The polar cranes are safety-related components designed to remain intact during seismic events. Therefore, the cranes and hoists system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

UFSAR References

Additional details of the cranes and hoists system can be found in the UFSAR, Section 9.12.4 and Appendix 9B.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the cranes and hoists system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-3, Cranes and Hoists.

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

2.3.3.4 Service Water

System Description

The service water system transfers heat from plant systems and components to the ultimate heat sink provided by the circulating water system. Cooling water flows from the Intake Canal to the service water system through branch lines from the circulating water system piping. The service water system includes diesel-driven emergency service water pumps located at the Low-Level Intake Structure in the Emergency Service Water Pump House that are designed to provide water from the James River to the Intake Canal during emergency conditions when the circulating water pumps are unavailable. The service water system also consists of components that provide cooling water to the bearing cooling water heat exchanger, the component cooling heat exchangers, the recirculation spray heat exchangers, the control room and relay room air conditioning system chiller condensers, the charging pump lubricating oil coolers, and the charging pump cooling water system intermediate seal coolers.

System Evaluation Boundary

The evaluation boundary for the service water system components subject to aging management review consists of the emergency service water pumps and flow path components, and components that provide cooling water to and from the recirculation spray heat exchangers, the component cooling heat exchangers, the bearing cooling heat exchangers, the control room chiller condensers, and the charging pump lubricating oil and seal water cooling subsystem. The emergency service water pump diesel engines themselves and attached/skid-mounted subcomponents are part of the active assembly, not subject to aging management review.

System Intended Functions

Portions of the service water system perform the following safety-related functions: The system provides cooling water to the recirculation spray system to depressurize the Containment and provide adequate core cooling following a design basis event. Also, the system provides cooling water to the component cooling water system, the control room air conditioning condensers, the charging pump intermediate seal coolers, and lube oil coolers. In addition, the system provides containment isolation function, safety-related indication and an emergency source of makeup water to ensure adequate Intake Canal inventory following a design basis event. Therefore, the service water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the service water system include spray shields to mitigate flooding. In addition, portions of the service water system contain 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, structural integrity and to mitigate flooding.

Portions of the service water system are 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).

UFSAR References

Additional details of the service water system can be found in the UFSAR, Section 9.9, Appendix 9C.1.1, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-071A Sht 1

11448-SLRM-071A Sht 2

11448-SLRM-071A Sht 3

11448-SLRM-071A Sht 4

11448-SLRM-071B Sht 1

11448-SLRM-071D Sht 1

11448-SLRM-071D Sht 2

11448-SLRM-071D Sht 3

11448-SLRM-071E Sht 1

11448-SLRM-077C Sht 1

11448-SLRM-130A Sht 1

11548-SLRM-071A Sht 2

11548-SLRM-071A Sht 3

11548-SLRM-071B Sht 1

11548-SLRM-130A Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.5 Circulating Water

System Description

The circulating water system provides the source of water for the ultimate heat sink during normal and emergency plant operations. Circulating water pumps discharge water from the James River to the Intake Canal. The Intake Canal water level is at a higher elevation than the Discharge Canal, and water flows to plant systems and components by gravity flow. The circulating water system provides a heat sink for the main condenser and is the source of water for the service water system. The main condenser is provided with inlet and outlet circulating water isolation valves that automatically close to mitigate Turbine Building flooding and to conserve Intake Canal inventory during accident conditions.

System Evaluation Boundary

The portion of the circulating water system subject to aging management review consists of the components from the Intake Canal to the main condenser (circulating water condenser) inlet, the main condenser channel heads, tubesheet, and tubes, and the components from the main condenser outlet to the Discharge Tunnel. The main condenser shell/hotwell are addressed within the condensate system.

System Intended Functions

Portions of the circulating water system perform the following safety-related functions: The circulating water system maintains adequate Intake Canal level to ensure plant cooling following a design basis event. Also, the circulating water system provides a means to minimize or isolate leakage to mitigate Turbine Building flooding. In addition, the circulating water system provides canal level input to the reactor protection system. Therefore, the circulating water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the circulating water system contain nonsafety-related components whose integrity assures adequate Intake Canal level during a design basis event, contain spray shields to mitigate internal flooding, and also 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) to maintain Intake Canal level, to mitigate flooding, and for spatial interaction and structural integrity.

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

UFSAR References

Additional details of the circulating water system can be found in the UFSAR, Section 9.9.3, Section 10.3.4, and Appendix 9C.1.1.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-071A Sht 2

11548-SLRM-071A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-5, Circulating Water.

The aging management review results for these component types are indicated in Table 3.3.2-5, Auxiliary Systems - Circulating Water - Aging Management Evaluation.

2.3.3.6 Bearing Cooling

System Description

The bearing cooling system is an intermediate cooling system that transfers heat from nonsafety-related plant systems and components to the service water system. The system also provides makeup water to various systems. The bearing cooling system is a closed cooling water system utilizing a corrosion inhibitor.

System Evaluation Boundary

The evaluation boundary for the bearing cooling system components subject to aging management review includes the passive water-retaining components. These comprise the safety-related piping and components attached to the control room air conditioning chilled water portion of the ventilation system, and nonsafety-related components within buildings containing safety-related components. These nonsafety-related components include surge (head) tanks, chemical addition tanks, pumps, the system heat exchangers that transfer heat to the service water system, the isophase bus duct coolers, and distribution piping components and valves supplying various heat exchangers associated with other systems in the Turbine and Service Buildings and Mechanical Equipment Rooms, as well as makeup supplies to various systems in these areas.

System Intended Functions

Portions of the bearing cooling system perform the following safety-related functions: The system provides a safety-related pressure boundary for the control room air conditioning chilled water portion of the ventilation system. Therefore, the bearing cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the bearing cooling system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the bearing 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.

UFSAR References

Additional details of the bearing cooling system can be found in the UFSAR, Section 10.3.9.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-073A Sht 1

11448-SLRM-073A Sht 2

11448-SLRM-073B Sht 1

11448-SLRM-074A Sht 1

11548-SLRM-073A Sht 1

11548-SLRM-073A Sht 2

11548-SLRM-073B Sht 1

11548-SLRM-074A Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.7 Chilled Water

System Description

The chilled water system provides cooling to the chilled component cooling heat exchangers. Chilled water is also used directly to cool the water in the refueling water storage tank after a refueling operation. Each unit has an independent, closed-loop chilled water system. A third full-size spare chiller unit is provided with cross-tie chilled water piping to permit use by either unit. Manual valves are provided for component isolation and for cross-connections. The UFSAR includes the chilled water system as one of the subsystems of component cooling systems.

System Evaluation Boundary

The evaluation boundary for the chilled water system components subject to aging management review includes the fluid-retaining components within buildings that house safety-related equipment. These include surge tanks, pumps, chiller components, the chilled component cooling heat exchangers, and the associated flowpath piping components and valves. Additionally, the refueling water storage tank coolers are nonsafety-related base-mounted components that provide support to safety-related containment spray piping components in the yard, and are subject to aging management review.

System Intended Functions

Portions of the chilled water system contain 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.

UFSAR References

Additional details of the chilled water system can be found in the UFSAR, Section 9.4.1.3 and Section 9.4.3.3.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-072D Sht 4

11448-SLRM-072D Sht 5

11448-SLRM-072F Sht 1

11448-SLRM-072F Sht 2

11448-SLRM-072H Sht 1

11448-SLRM-084A Sht 1

11548-SLRM-072D Sht 1

11548-SLRM-084A Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.8 Component Cooling

System Description

The component cooling system is an intermediate cooling system that transfers heat from plant primary systems and components to the service water system. The component cooling system serves safety-related and nonsafety-related systems and components that contain potentially radioactive fluids. The component cooling system is a closed cooling water system utilizing a corrosion inhibitor.

System Evaluation Boundary

The evaluation boundary for the component cooling system components subject to aging management review includes both safety-related and nonsafety-related piping and components, and includes surge tanks, chemical addition tanks, pumps, the system heat exchangers that transfer heat to the service water system, penetration coolers and shield wall coolers, and distribution piping components and valves supplying various heat exchangers associated with other systems. Additionally, some air-operated valves are provided with air accumulators (tanks) or connections for portable gas bottle supply to ensure valve operation capability. These air tanks and the associated piping components and valves are also subject to aging management review.

Coolers and heat exchangers in other systems that are cooled by component cooling water are evaluated with their parent systems.

System Intended Functions

Portions of the component cooling system perform the following safety-related functions: The system provides containment isolation, provides cooling to safety-related equipment and provides safety-related indication. Therefore, the component cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the component cooling system perform the following nonsafety-related functions: The system provides cooling and pressure boundaries in support of safety-related functions. Additionally, portions of the component cooling system contain 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) to provide cooling and pressure boundary, and for spatial interaction and structural integrity.

Portions of the component cooling system are 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).

UFSAR References

Additional details of the component cooling system can be found in the UFSAR, Section 9.4.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-071B Sht 2

11448-SLRM-072A Sht 1

11448-SLRM-072A Sht 2

11448-SLRM-072A Sht 3

11448-SLRM-072A Sht 4

11448-SLRM-072A Sht 5

11448-SLRM-072A Sht 6

11448-SLRM-072A Sht 7

11448-SLRM-072B Sht 1

11448-SLRM-072B Sht 2

11448-SLRM-072B Sht 3

11448-SLRM-072C Sht 1

11448-SLRM-072C Sht 2

11448-SLRM-072C Sht 3

11448-SLRM-072C Sht 4

11448-SLRM-072C Sht 5

11448-SLRM-072D Sht 1

11448-SLRM-072D Sht 2

11448-SLRM-072D Sht 3

11448-SLRM-072D Sht 5

11448-SLRM-072E Sht 1

11448-SLRM-072E Sht 2

11448-SLRM-072G Sht 1

11448-SLRM-079C Sht 1

11548-SLRM-071B Sht 2

11548-SLRM-072A Sht 1

11548-SLRM-072A Sht 2

11548-SLRM-072A Sht 3

11548-SLRM-072A Sht 4

11548-SLRM-072A Sht 5

11548-SLRM-072A Sht 6

11548-SLRM-072A Sht 7

11548-SLRM-072B Sht 1

11548-SLRM-072B Sht 2

11548-SLRM-072B Sht 3

11548-SLRM-072C Sht 1

11548-SLRM-072C Sht 2

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 Neutron Shield Tank Cooling

System Description

The neutron shield tank cooling system provides cooling for the neutron shield tank fluid which is heated by attenuation of neutron and gamma radiation in the vicinity of the reactor vessel. Heat removal is provided by the component cooling system. The neutron shield tank cooling system also removes heat from the primary shield wall. The UFSAR includes the neutron shield tank cooling system as one of the subsystems of component cooling systems.

Two neutron shield tank coolers, a neutron shield surge tank, a corrosion control tank, the shield wall coolers, and necessary piping and valves comprise the system serving each reactor unit. Each neutron shield tank cooler has 100 percent capacity. The second cooler is a spare that can be placed in operation remotely by means of motor-operated valves.

System Evaluation Boundary

The evaluation boundary for the neutron shield tank cooling system components subject to aging management review includes the shield wall cooler panels, neutron shield tank coolers, surge tank and associated flowpath piping and components, as well as nonsafety-related valves and piping components within the Containment that perform a leakage boundary function. The neutron shield tank itself is evaluated with the reactor coolant system for its pressure boundary function, and is evaluated in the structural section of the subsequent license renewal application for its structural support function.

System Intended Functions

Portions of the neutron shield tank cooling system perform the following safety-related functions: The system removes heat from the primary shield wall and provides a pressure boundary for the component cooling system. Therefore, the neutron shield tank cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the neutron shield tank cooling system contain nonsafety-related components that support cooling of the neutron shield tank, and portions also contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the neutron shield tank cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for neutron shield tank cooling, and for spatial interaction and structural integrity.

UFSAR References

Additional details of the neutron shield tank cooling system can be found in the UFSAR, Section 9.4.1.4, Section 9.4.3.1, and Section 9.4.3.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the neutron shield tank cooling system are listed below:

11448-SLRM-072A Sht 7

11448-SLRM-072E Sht 2

11548-SLRM-072A Sht 7

11548-SLRM-072B Sht 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-9, Neutron Shield Tank Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-9, Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation.

2.3.3.10 Primary Grade Water

System Description

The primary grade water system provides treated water to plant systems for makeup, flushing, cooling, and other uses. Portions of the primary grade water system provide a pressure boundary for the chemical and volume control system and the fuel pool cooling system.

System Evaluation Boundary

Portions of the primary grade water system subject to aging management review include the safety-related valve connections to the fuel pool cooling system, and nonsafety-related, water-filled piping components within buildings containing safety-related components. These nonsafety-related components provide primary grade water for various uses including: fuel pit cooling makeup (downstream of the safety-related valves), instrument air compressor cooling, flush water for demineralizers, blender supply and makeup and flush water for chemical addition for the chemical and volume control system, makeup to the pressurizer relief tank, seal water for small pumps, and other miscellaneous uses.

System Intended Functions

Portions of the primary grade water system perform the following safety-related functions: Provide safety-related supply/isolation connections to the fuel pool cooling system. Therefore, the primary grade water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the primary grade water system contain nonsafety-related components that provide a functional pressure boundary for the chemical and volume control system and the fuel pit cooling system, and portions also contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the primary grade water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, and for spatial interaction and structural integrity.

UFSAR References

Additional details of the primary grade water system can be found in the UFSAR, Section 9.2, Section 9.2.1, and Table 9.2-1.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-079C Sht 1

11448-SLRM-079D Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-10, Primary Grade Water.

The aging management review results for these component types are indicated in Table 3.3.2-10, Auxiliary Systems - Primary Grade Water - Aging Management Evaluation.

2.3.3.11 Instrument Air

System Description

The instrument air system provides a reliable source of clean, dry, oil-free compressed air to air-operated valves, instruments, and other miscellaneous components in the plant. The UFSAR includes the instrument air system as one of the subsystems of the compressed air system. Critical components that require compressed air in order to perform intended functions are provided with back-up subsystems and do not rely upon the normal instrument air system as the sole source of compressed air. The following air-operated components are provided with back-up compressed air accumulators:

- Pressurizer power-operated relief valves
- Feedwater flow and bypass flow control valves
- Selected ventilation exhaust system dampers
- Component cooling containment isolation valves from residual heat removal
- Main steam power-operated relief valves
- Main steam supply valves for the auxiliary feedwater turbines

Additional valves may be operated locally using portable stored gas bottles, hose, and valves, as well as blocking devices to clamp the valve stems in place after local operation:

- Residual heat removal letdown control valves
- Chemical and volume control letdown isolation and auxiliary spray valves

System Evaluation Boundary

The evaluation boundary for the instrument air system components subject to aging management review includes the safety-related containment penetration piping and isolation valves, the air or gas supply to selected air-operated valves and dampers, the containment instrument air compressor heat exchangers, the nonsafety-related components that provide support to directly connected safety-related components, and the components associated with air compressors or drain traps (at compressors, air receivers and air dryers) that retain water or oil in buildings containing safety-related components. Also subject to aging management are the stored gas bottles, hose, valves and blocking devices used to support local operation of air-operated valves.

System Intended Functions

Portions of the instrument air system perform the following safety-related functions: The system provides containment isolation, provides safety-related indication, and provides a backup air or gas supply to support the safety-related functions of select air-operated 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).

Portions of the instrument air system contain nonsafety-related components that provide a pressure boundary for the component cooling system, as well as 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 pressure boundary integrity and for spatial interaction and structural integrity.

Portions of the instrument air system are 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 instrument air system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the instrument air system can be found in the UFSAR, Section 9.8, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRK-8M SHT 1

11448-SLRM-075A Sht 1

11448-SLRM-075A Sht 2

11448-SLRM-075C Sht 1

11448-SLRM-075C Sht 3

11448-SLRM-075D Sht 1

11448-SLRM-075E Sht 1

11448-SLRM-075E Sht 2

11448-SLRM-075J Sht 1

11548-SLRK-8G SHT 1

11548-SLRM-075B Sht 2

11548-SLRM-075C Sht 1

11548-SLRM-075C Sht 2

11548-SLRM-075D Sht 1

11548-SLRM-075J Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.12 Primary and Secondary Plant Gas Supply

System Description

The primary and secondary plant gas supply system provides compressed gas for various plant uses.

System Evaluation Boundary

The evaluation boundary for the primary and secondary plant gas supply system components subject to aging management review includes the safety-related nitrogen lines connecting to the main steam lines back to their nonsafety-related transitions, safety-related containment penetration piping, and the associated nonsafety-related components that provide support to directly connected safety-related components. Additionally, nonsafety-related vacuum pump, tank and piping components that may retain water are within the evaluation boundary.

System Intended Functions

Portions of the primary and secondary plant gas supply system perform the following safety-related functions: The system provides containment isolation and provides a pressure boundary for the main steam system. Therefore, the primary and secondary plant gas supply system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the primary and secondary plant gas supply system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the primary and secondary plant gas 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.

UFSAR References

Additional details of the primary and secondary plant gas supply system can be found in the UFSAR, Section 6.2.2.2.1, Section 10.3.1.2, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the primary and secondary plant gas supply system are listed below:

11448-SLRM-064B Sht 1

11448-SLRM-089A Sht 3

11448-SLRM-089B Sht 1

11548-SLRM-064B Sht 1

11548-SLRM-089A Sht 3

11548-SLRM-089B Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-12, Primary and Secondary Plant Gas Supply.

The aging management review results for these component types are indicated in Table 3.3.2-12, Auxiliary Systems - Primary and Secondary Plant Gas Supply - Aging Management Evaluation.

2.3.3.13 Service Air

System Description

The service air system provides a source of compressed air to support plant general service compressed air requirements. The service air system is the normal source of compressed air to the instrument air system. The UFSAR includes the service air system as one of the subsystems of the compressed air system.

System Evaluation Boundary

The evaluation boundary for the service air system components subject to aging management review includes the containment penetration piping and isolation valves, the associated directly connected nonsafety-related components that provide support to these safety-related components, and moisture traps and associated fluid-retaining piping components in buildings containing safety-related components.

System Intended Functions

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

Portions of the service air system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the service 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.

UFSAR References

Additional details of the service air system can be found in the UFSAR, Section 9.8, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-075A Sht 1

11448-SLRM-075A Sht 3

11448-SLRM-075F Sht 1

11448-SLRM-075G Sht 1

11548-SLRM-075E Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.14 Boron Recovery

System Description

The boron recovery system is a common system serving both units. The system de-gasifies and stores borated radioactive water letdown by the chemical and volume control system or gaseous drain water transferred by the drains gaseous system.

System Evaluation Boundary

The evaluation boundary for the boron recovery system components subject to aging management review includes nonsafety-related boron recovery heat exchangers that provide a pressure boundary function for the component cooling system supply, as well as boron recovery components that provide a pressure boundary function or provide structural support for connected safety-related components. Also subject to aging management review are boron recovery system components that retain water or steam in buildings containing safety-related components.

System Intended Functions

Portions of boron recovery system perform the following safety-related functions: The system contains safety-related components that provide a pressure boundary function. Therefore, the boron recovery system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the boron recovery system contain nonsafety-related components that provide a pressure boundary for attached systems, and portions contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, boron recovery system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary, spatial interaction and structural integrity.

UFSAR References

Additional details of the boron recovery system can be found in the UFSAR, Section 9.2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-072B Sht 2

11448-SLRM-072C Sht 2

11448-SLRM-072D Sht 3

11448-SLRM-079A Sht 1

11448-SLRM-079A Sht 2

11448-SLRM-079A Sht 3

11448-SLRM-079B Sht 1

11448-SLRM-079B Sht 2

11448-SLRM-079C Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.15 Chemical and Volume Control

System Description

The chemical and volume control system provides reactor coolant system letdown and makeup 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 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.

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 nonregenerative 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 charging pump seal coolers and oil pumps, heat exchangers and flowpaths, and nonsafety-related components that retain water or steam in buildings containing safety-related components. Additionally subject to aging management review are local air valves and air supply piping for select letdown isolation valves that are credited for post-fire operation using a portable air bottle.

System Intended Functions

Portions of the chemical and volume control system perform the following safety related functions: The system provides a pressure boundary for the reactor coolant system, controls reactor coolant system inventory and pressure, controls core reactivity, provides high-head safety injection flow, provides reactor coolant pump seal injection, provides safety-related instrumentation, and provides containment isolation. 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).

Portions of the chemical and volume control system contain 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.

Portions of the chemical and volume control system are 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).

UFSAR References

Additional details of the chemical and volume control system can be found in the UFSAR, Section 9.1, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-071B Sht 2

11448-SLRM-088A Sht 1

11448-SLRM-088A Sht 2

11448-SLRM-088A Sht 3

11448-SLRM-088A Sht 4

11448-SLRM-088B Sht 1

11448-SLRM-088B Sht 2

11448-SLRM-088B Sht 3

11448-SLRM-088C Sht 1

11448-SLRM-088C Sht 2

11548-SLRM-071B Sht 2

11548-SLRM-088A Sht 1

11548-SLRM-088A Sht 2

11548-SLRM-088B Sht 1

11548-SLRM-088B Sht 2

11548-SLRM-088B Sht 3

11548-SLRM-088C Sht 1

11548-SLRM-088C Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-15, Chemical and Volume Control.

The aging management review results for these component types are indicated in Table 3.3.2-15, Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation.

2.3.3.16 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 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 guide tubes and seal table fittings form a pressure boundary for the reactor coolant system. The isolation valves normally do not provide a reactor coolant system pressure boundary, but are designed to be closed in the event of a leak in the incore instrumentation system pressure boundary components. If closed, the isolation valves form the reactor coolant system pressure boundary.

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 flux thimble tubes and plugs 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.

System Intended Functions

Portions of the incore instrumentation system perform the following safety-related function: The system provides a pressure boundary for the reactor coolant system in the event of a flux thimble tube leak. Therefore, the incore instrumentation system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the incore instrumentation system can be found in the UFSAR, Section 7.6.

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 2.3.3-16, Incore Instrumentation.

The aging management review results for these component types are indicated in Table 3.3.2-16, Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation.

2.3.3.17 Reactor Cavity Purification

System Description

The reactor cavity purification system provides a means to maintain the water quality of the filled reactor cavity during refueling operations. The system also includes the capability to pump the reactor cavity water to the refueling water storage tank.

System Evaluation Boundary

The evaluation boundary for the reactor cavity purification system components subject to aging management review includes safety-related containment penetration piping components, nonsafety-related piping components that provide a pressure boundary for the reactor cavity (when filled) and nonsafety-related pumps and components that provide support to directly connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

Portions of the reactor cavity purification system perform the following safety-related functions: The system provides containment isolation and provides pressure boundary integrity for connected safety-related systems. Therefore, the reactor cavity purification system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the reactor cavity purification system contain nonsafety-related components that provide a pressure boundary for the reactor cavity (when filled), and also contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the reactor cavity purification system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for refueling cavity integrity and for spatial interaction and structural integrity.

UFSAR References

Additional details of the reactor cavity purification system can be found in the UFSAR, Section 9.12.5, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-118A Sht 1

11448-SLRM-118A Sht 2

11548-SLRM-118A Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-17, Reactor Cavity Purification.

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

2.3.3.18 Sampling System

System Description

The sampling system provides a means to monitor fluid quality and other system performance parameters for various plant systems. The sampling system consists of sample piping, valves, sample coolers, and other components that provide for the control of sample streams. Sample cooling is provided by the component cooling and bearing cooling systems. The sampling system includes the high radiation sampling system which can be used to provide indications of post-accident plant conditions.

System Evaluation Boundary

The evaluation boundary for the sampling system components subject to aging management review includes the safety-related piping components attached to safety-related systems, safety-related containment penetration piping components, 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. Nonsafety-related fluid-retaining components within the high radiation liquid sample panel, chemical analysis panel and containment air sample panel are not within-scope for leakage boundary function, because the panels are designed to contain potential internal leakage (UFSAR Section 9.6.2.2). The sample panels are within-scope for this function and are addressed in the structural section of this subsequent license renewal application.

System Intended Functions

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

Portions of the sampling system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the 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.

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

UFSAR References

Additional details of the sampling system can be found in the UFSAR, Section 9.6, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-073B Sht 1

11448-SLRM-082A Sht 1

11448-SLRM-082A Sht 2

11448-SLRM-082B Sht 2

11448-SLRM-082C Sht 1

11448-SLRM-082D Sht 1

11448-SLRM-082E Sht 1

11448-SLRM-082E Sht 2

11448-SLRM-082E Sht 3

11448-SLRM-082F Sht 1

11448-SLRM-082F Sht 2

11448-SLRM-082F Sht 3

11448-SLRM-082F Sht 4

11448-SLRM-082J Sht 1

11448-SLRM-082J Sht 2

11448-SLRM-082K Sht 1

11448-SLRM-082K Sht 2

11548-SLRM-073B Sht 1

11548-SLRM-082A Sht 2

11548-SLRM-082A Sht 3

11548-SLRM-082C Sht 1

11548-SLRM-082D Sht 1

11548-SLRM-082D Sht 2

11548-SLRM-082D Sht 3

11548-SLRM-082D Sht 4

11548-SLRM-082E Sht 1

11548-SLRM-082E Sht 2

11548-SLRM-083B Sht 3

Components Subject to Aging Management Review

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

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

2.3.3.19 Decontamination

System Description

The decontamination system collects drainage from the Decontamination Building work areas and the building sump. The decontamination system provides a means for transferring the collected waste to the liquid waste system.

System Evaluation Boundary

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

System Intended Functions

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

UFSAR References

Additional details of the decontamination system can be found in the UFSAR, Section 9.14.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the decontamination system is listed below:

11448-SLRM-080C Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.20 Drains Aerated

System Description

The drains aerated system collects potentially radioactive fluids in building sumps and discharges the sump fluids to the waste disposal system for processing and disposal. The UFSAR includes the drains aerated system as a subsystem of the vent and drain system.

System Evaluation Boundary

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

System Intended Functions

Portions of the drains aerated system perform the following safety-related functions: The system provides containment isolation function and provides non-EQ safety-related instrumentation. Therefore, the drains aerated system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the drains aerated system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the drains aerated 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.

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

UFSAR References

Additional details of the drains aerated system can be found in the UFSAR, Section 9.7, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the drains aerated system are listed below:

11448-SLRM-072D Sht 1

11448-SLRM-082A Sht 1

11448-SLRM-083A Sht 2

11448-SLRM-083A Sht 3

11448-SLRM-083B Sht 3

11448-SLRM-083C Sht 1

11448-SLRM-088A Sht 3

11448-SLRM-088A Sht 4

11448-SLRM-090B Sht 1

11448-SLRM-124A Sht 1

11448-SLRM-124A Sht 2

11448-SLRM-124A Sht 3

11548-SLRM-083A Sht 1

11548-SLRM-083B Sht 3

11548-SLRM-088A Sht 1

11548-SLRM-088A Sht 2

11548-SLRM-124A Sht 1

11548-SLRM-124A Sht 2

11548-SLRM-124A Sht 3

Components Subject to Aging Management Review

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

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

2.3.3.21 Drains Gaseous

System Description

The drains gaseous system collects potentially radioactive fluids. The drains gaseous system distributes these fluids via the primary drains transfer tank and cooler to the boron recovery system for processing and recovery. The UFSAR includes the drains gaseous system as a subsystem of the vent and drain system.

System Evaluation Boundary

The evaluation boundary for the drains gaseous system components subject to aging management review includes the safety-related primary drain coolers and containment penetration piping 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

Portions of the drains gaseous system perform the following safety-related functions: The system provides a pressure boundary for attached safety-related systems, provides containment isolation and provides safety-related instrumentation. Therefore, the drains gaseous system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the drains gaseous system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the drains gaseous 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.

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

UFSAR References

Additional details of the drains gaseous system can be found in the UFSAR, Section 9.7, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-072E Sht 2

11448-SLRM-083A Sht 1

11448-SLRM-083A Sht 2

11448-SLRM-083B Sht 1

11448-SLRM-083B Sht 2

11448-SLRM-083B Sht 3

11448-SLRM-088B Sht 2

11448-SLRM-089A Sht 2

11548-SLRM-072B Sht 3

11548-SLRM-083A Sht 1

11548-SLRM-083A Sht 2

11548-SLRM-083B Sht 1

11548-SLRM-083B Sht 2

11548-SLRM-083B Sht 3

11548-SLRM-088B Sht 2

11548-SLRM-089A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-21, Drains Gaseous.

The aging management review results for these component types are indicated in Table 3.3.2-21, Auxiliary Systems - Drains Gaseous - Aging Management Evaluation.

2.3.3.22 Gaseous Waste

System Description

The gaseous waste system provides holding capacity and processing for potentially radioactive gases collected from various plant systems. The gaseous waste system also provides the capability to monitor the post-accident containment atmosphere hydrogen concentration via the hydrogen analyzers.

System Evaluation Boundary

The evaluation boundary for the gaseous waste system components subject to aging management review includes the safety-related components that are associated with containment hydrogen monitoring, safety-related components that provide a containment isolation function, and nonsafety-related components that provide support to directly connected safety-related components, or that retain water in buildings containing safety-related components. The hydrogen recombiner subsystem is no longer credited in the design basis or safety analysis.

System Intended Functions

Portions of the gaseous waste system perform the following safety-related functions: The system provides containment hydrogen monitoring, provides containment isolation, and provides safety-related instrumentation. Therefore, the gaseous waste system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the gaseous waste system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the gaseous waste 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.

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

UFSAR References

Additional details of the gaseous waste system can be found in the UFSAR, Section 5.3.5, Section 6.2.3.12, Section 11.2.5, Section 14.4.2.2, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-072C Sht 4

11448-SLRM-090B Sht 1

11448-SLRM-090B Sht 2

11448-SLRM-090C Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.23 Liquid and Solid Waste

System Description

The liquid and solid waste system is common to both reactor units and provides for collection, treatment and disposal of the radioactive wastes produced during operation of the two units. The purpose of the liquid and solid waste system is to collect and transfer liquid waste to the Surry Radwaste Facility and to process resins into high integrity containers for transfer offsite.

System Evaluation Boundary

The evaluation boundary for the liquid waste system components subject to aging management review includes the nonsafety-related waste evaporator distillate cooler, which provides 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 in buildings containing safety-related components.

System Intended Functions

Portions of the liquid and solid waste system contain nonsafety-related components that provide a functional pressure boundary to support safety-related system integrity, and portions contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the liquid and solid waste system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for maintaining pressure boundary, and for spatial interaction and structural integrity.

UFSAR References

Additional details of the liquid and solid waste system can be found in the UFSAR, Section 11.2.3 and Section 11.2.4.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-080A Sht 1

11448-SLRM-080B Sht 1

11448-SLRM-080C Sht 1

11448-SLRM-080D Sht 1

11448-SLRM-80E SHT1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-23, Liquid and Solid Waste.

The aging management review results for these component types are indicated in Table 3.3.2-23, Auxiliary Systems - Liquid and Solid Waste - Aging Management Evaluation.

2.3.3.24 Plumbing

System Description

The plumbing system, in addition to normal services, prevents or mitigates station flooding. The system comprises turbine building sumps, floor and roof drains system, sanitary sewer components, electrical manhole sump pumps, the containment sub-surface drain pumps and the yard storm drains.

The turbine building sump system consists of three sumps, each containing three high-volume sump pumps, and the associated valves, instruments, and piping. The Turbine Building sump pumps have sufficient capacity to prevent flooding from less severe leaks and normal events such as runoff from storms.

The containment sub-surface drain pumps minimize the hydrostatic pressure on the containment mat liner.

The electrical manhole sump pumps dewater the underground electrical manholes.

The yard storm drains use polymer cured-in-place piping to remove rainwater from the yard to mitigate potential flooding during maximum precipitation events.

System Evaluation Boundary

The evaluation boundary for the plumbing system components subject to aging management review includes the nonsafety-related pumps and piping components that provide Turbine Building flood protection and the yard storm drain piping (for which neither have system drawings available) and dewatering around the containment mat liner. Also subject to aging management review are nonsafety-related components that retain water in structures containing safety-related components. These components include sanitary sewer components, some of which are depicted on system drawings, and floor and roof drain piping, as well as sump pumps and discharge piping components within electrical manholes that contain safety-related cabling, for which no system drawings are available. In addition, electrical manhole sump pumps and discharge piping components within the manholes that support station blackout recovery are also subject to aging management review. No system drawings are available for these components. Manholes are managed as part of structural commodities.

System Intended Functions

Portions of the plumbing system contain nonsafety-related components that support pumping liquid from the turbine building sumps, the containment sub-surface drains and also remove rainwater from the yard to mitigate potential flooding. In addition, portions of the plumbing system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the plumbing system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for water removal, and for spatial interaction.

Portions of the plumbing system are relied upon for compliance with regulations for Station Blackout (10 CFR 50.63). Therefore, the plumbing system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the plumbing system can be found in the UFSAR, Appendix 9C, Section 15.5.1.1, and Section 15.5.1.3.

Subsequent License Renewal Boundary Drawings

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

11448-SLRB-56A Sht 1

11448-SLRM-075C Sht 4

11448-SLRM-075C Sht 5

Components Subject to Aging Management Review

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

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

2.3.3.25 Radiation Monitoring

System Description

The radiation monitoring system provides indication of radiation conditions in various plant areas and within potentially radioactive plant systems.

System Evaluation Boundary

The evaluation boundary for the radiation monitoring system components subject to aging management review includes the safety-related containment penetration piping components and nonsafety-related components that provide structural integrity for the safety-related components.

Other radiation monitoring sample flowpaths are evaluated within the systems being monitored.

System Intended Functions

Portions of the radiation monitoring system perform the following safety-related function: The radiation monitoring system provides containment isolation function. Therefore, the radiation monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the radiation monitoring system contain 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 structural integrity.

Portions of the radiation monitoring system are 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).

UFSAR References

Additional details of the radiation monitoring system can be found in the UFSAR, Section 11.3.3, Section 11.3.4, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-130B Sht 1

11548-SLRM-130B Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-25, Radiation Monitoring.

The aging management review results for these component types are indicated in Table 3.3.2-25, Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation.

2.3.3.26 Vents Aerated

System Description

The vents aerated system collects and processes gases vented from various potentially radioactive systems. The UFSAR includes the vents aerated system as a subsystem of the vent and drain system.

System Evaluation Boundary

The evaluation boundary for the vents aerated system components subject to aging management review includes the safety-related containment penetration piping components, and the 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

Portions of the vents aerated system perform the following safety-related function: The vents aerated system provides containment isolation function. Therefore, the vents aerated system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the vents aerated system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the vents aerated 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.

UFSAR References

Additional details of the vents aerated system can be found in the UFSAR, Section 9.7, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the vents aerated system are listed below:

11448-SLRM-083A Sht 1

11448-SLRM-083B Sht 3

11448-SLRM-088A Sht 2

11448-SLRM-088A Sht 3

11448-SLRM-088A Sht 4

11448-SLRM-090B Sht 1

11548-SLRM-083B Sht 3

11548-SLRM-088A Sht 1

11548-SLRM-088A Sht 2

Components Subject to Aging Management Review

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

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

2.3.3.27 Vents Gaseous

System Description

The vents gaseous system collects and processes potentially radioactive gases vented from various plant systems. The UFSAR includes the vents gaseous system as a subsystem of the vent and drain system.

System Evaluation Boundary

The evaluation boundary for the vents gaseous system components subject to aging management review includes the safety-related containment penetration piping 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

Portions of the vents gaseous system perform the following safety-related functions: The system provides containment isolation and provides safety-related indication. Therefore, the vents gaseous system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the vents gaseous system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the vents gaseous 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.

Portions of the vents gaseous system are relied upon for compliance with regulations for environmental qualification (10 CFR 50.49). Therefore, the vents gaseous system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the vents gaseous system can be found in the UFSAR, Section 9.7, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-072E Sht 2

11448-SLRM-083A Sht 1

11448-SLRM-083B Sht 1

11448-SLRM-088C Sht 1

11548-SLRM-072B Sht 3

11548-SLRM-083A Sht 2

11548-SLRM-083B Sht 1

Components Subject to Aging Management Review

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

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

2.3.3.28 Water Treatment

System Description

The water treatment system produces, stores, and distributes high-purity water for use in the primary and secondary systems. This water is pumped to the primary grade water tanks for use in the primary systems and to the condensate storage tanks for use in the secondary systems. The system also provides for distribution of domestic (potable) water.

System Evaluation Boundary

The evaluation boundary for the water treatment system components subject to aging management review includes the 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

Portions of the water treatment system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the water treatment 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.

UFSAR References

Additional details of the water treatment system can be found in the UFSAR, Section 9.11.

Subsequent License Renewal Boundary Drawings

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

11448-SLRB-047D Sht 1

11448-SLRB-047D Sht 2

11448-SLRB-047D Sht 3

11448-SLRM-074A Sht 2

11448-SLRM-077A Sht 2

11448-SLRM-077B Sht 1

11448-SLRM-077B Sht 2

11448-SLRM-077B Sht 3

11448-SLRM-077F Sht 2

11448-SLRM-123A Sht 1

11448-SLRM-123A Sht 2

11548-SLRM-077A Sht 1

11548-SLRM-077A Sht 2

11548-SLRM-077D Sht 1

11548-SLRM-123A Sht 1

11548-SLRM-123A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-28, Water Treatment.

The aging management review results for these component types are indicated in Table 3.3.2-28, Auxiliary Systems - Water Treatment - Aging Management Evaluation.

2.3.3.29 Ventilation

System Description

The ventilation system is comprised of several ventilation subsystems with the general function to provide space and equipment cooling. Certain subsystems also provide radiological controls.

The following ventilation subsystems are within the scope of subsequent license renewal:

Auxiliary Ventilation

The auxiliary ventilation subsystem is comprised of fresh air supply and exhaust ventilation for the Auxiliary Building, Fuel Building, Decontamination Building and Safeguards Building, and a common filtration unit. The auxiliary ventilation subsystem also includes the exhaust ventilation filters, fans, dampers, and ductwork for the engineered safety features equipment areas (emergency system).

Containment Ventilation

The containment ventilation subsystem consists of containment air recirculation, control rod drive mechanism ventilation, and containment purge ventilation.

The containment air recirculation ventilation removes heat from the Containment during normal and shutdown operations. The control rod drive mechanism ventilation cools the ventilation air drawn from the control rod drive mechanism area of the reactor vessel head in order to remove heat generated in the head region. The containment purge provides for containment atmosphere air changes for radiological control and personnel habitability during plant shutdown conditions.

Main Control Room and Emergency Switchgear Room Ventilation

The main control room and emergency switchgear room ventilation subsystem is comprised of air-conditioning ventilation components and Control Room envelope emergency ventilation filtration and charcoal adsorber components. The Control Room envelope includes the main Control Room (including Control Room Annex area), Emergency Switchgear and Relay Rooms, safety-related Battery Rooms, associated stairwell, and Mechanical Equipment Room 3.The air-conditioning system consists of supply and exhaust ventilation, and a recirculation system. The supply and exhaust system is secured in an emergency in order to isolate the control room envelope. The recirculation air-conditioning system, including water chillers and associated equipment, air handling units, dampers, and ductwork, provides cooling during normal and emergency conditions

Other Ventilation Subsystems

The cable spreading room ventilation system provides cooling to the cable spreading area in the Service Building. Miscellaneous air conditioning units supply heated and/or cooled air within various plant areas.

The initial license renewal application included the control room bottled air pressurization subsystem within the scope of license renewal. License amendments, approved on 10/29/2009 (ML092660656), removed the requirements for the control room bottled air pressurization components. Analyses for control room habitability no longer credit the bottled air pressurization. With that licensing change, the control room bottled air pressurization components no longer perform a license renewal function, and the subsystem components are not within the scope of subsequent license renewal.

System Evaluation Boundary

The evaluation boundary for the auxiliary ventilation exhaust system components subject to aging management review includes exhaust ductwork and damper components from the Safeguards Building, Auxiliary Building, Fuel Building, and Decontamination Building through both the normal (unfiltered) and the filtered exhaust components to the vent stack.

The portion of the containment ventilation that is subject to aging management review is limited to the cooling coils that provide the component cooling system pressure boundary. The portion of the control rod drive mechanism shroud cooling subsystem that is subject to aging management review is limited to the cooling coils that provide the component cooling system pressure boundary. The portion of the containment purge that is subject to aging management review includes the supply fans and associated ductwork, dampers into Containment, and the exhaust ductwork and dampers through Containment, and through system filters to the discharge ducting, as well as attached nonsafety-related ductwork that provides support to attached safety-related components.

The control room air-conditioning components that are subject to aging management review are the ventilation system components that provide isolation and filtered breathing air for the control room envelope and the ventilation system components that provide control room cooling.

Other ventilation system components subject to aging management review include the cable spreading room ventilation ductwork, dampers and air handling units; battery room ventilation ductwork, dampers and fans; stored flexible hose used for post-fire temporary ventilation; and the fluid-retaining heating/cooling tubes in various area air handling units; as well as drip pans and associated condensate drains that are located in buildings containing safety-related components.

Additionally, the system includes both safety-related and nonsafety-related chilled water subsystems that provide cooling to various air conditioning units. The portions of these subsystems subject to aging management review include the circulating pumps, safety-related chillers, water-retaining portions of nonsafety-related chillers, the distribution piping system components, surge tank, and heat exchanger tubes.

System Intended Functions

Portions of the ventilation system perform the following safety-related functions: The system ventilates equipment areas and routes potentially contaminated air through charcoal filters prior to discharge to the environment, provides containment integrity (isolation), provides ventilation and breathing air to the control room, and provides safety-related instrumentation. Therefore, the ventilation system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the ventilation system contain nonsafety-related components that ventilate the charging pump cubicles for temperature control, and portions also contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the ventilation system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for ventilation, and for spatial interaction and structural integrity.

Portions of the ventilation system are 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 ventilation system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the ventilation system can be found in the UFSAR, Section 5.3.1, Section 9.10.4.4, Section 9.13, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRB-006A Sht 1

11448-SLRB-006D Sht 1

11448-SLRB-006D Sht 2

11448-SLRB-006D Sht 3

11448-SLRB-006D Sht 4

11448-SLRB-037C Sht 1

11448-SLRB-037D Sht 1

11448-SLRB-037E Sht 1

11448-SLRB-041A Sht 1

11448-SLRB-041A Sht 2

11448-SLRB-041A Sht 3

11448-SLRB-041A Sht 4

11448-SLRM-071D Sht 1

11448-SLRM-071D Sht 2

11448-SLRM-072B Sht 2

11548-SLRB-006A Sht 1

11548-SLRM-072B Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-29, Ventilation.

The aging management review results for these component types are indicated in Table 3.3.2-29, Auxiliary Systems - Ventilation - Aging Management Evaluation.

2.3.3.30 Leakage Monitoring

System Description

The leakage monitoring system provides containment pressure signals to the engineered safety features actuation system. The system is also designed to provide pressure sensing during containment leakrate testing.

System Evaluation Boundary

The evaluation boundary for the leakage monitoring system components that are subject to aging management review includes the safety-related piping and valves associated with the containment penetrations, and the attached nonsafety-related components that provide support.

System Intended Functions

Portions of the leakage monitoring system perform the following safety-related functions: The system provides containment integrity and provides safety-related indication and input to the reactor protection system. Therefore, the leakage monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

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

UFSAR References

Additional details of the leakage monitoring system can be found in the UFSAR, Section 5.3.2, Section 7.5.1.2, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-085A Sht 1

11448-SLRM-085A Sht 2

11548-SLRM-085A Sht 1

11548-SLRM-085A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-30, Leakage Monitoring.

The aging management review results for these component types are indicated in Table 3.3.2-30, Auxiliary Systems - Leakage Monitoring - Aging Management Evaluation.

2.3.3.31 Secondary Vents

System Description

The secondary vents system provides a vent path for non-condensable gases discharged by the main condenser air ejectors.

System Evaluation Boundary

The evaluation boundary for the secondary vents system components subject to aging management review includes the safety-related piping and valves associated with the containment penetration, and the attached nonsafety-related piping that provides support.

System Intended Functions

Portions of the secondary vents system perform the following safety-related functions: The system provides containment integrity and safety-related indication. Therefore, the secondary vents system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

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

UFSAR References

Additional details of the secondary vents system can be found in the UFSAR, Section 10.3.8, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the secondary vents system are listed below:

11448-SLRM-066A Sht 1

11548-SLRM-066A Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-31, Secondary Vents.

The aging management review results for these component types are indicated in Table 3.3.2-31, Auxiliary Systems - Secondary Vents - Aging Management Evaluation.

2.3.3.32 Vacuum Priming

System Description

The vacuum priming system removes non-condensable gases from various plant systems. The vacuum priming system also provides a circulating water system pressure boundary function at the vacuum priming tank drain connection to the main condenser outlet circulating water pipe and a service water system pressure boundary at the vacuum priming connections to the component cooling water heat exchangers.

System Evaluation Boundary

The evaluation boundary for the vacuum priming system components that are subject to aging management review consists of the safety-related vacuum priming piping components and valves connected to the service water side of the component cooling heat exchangers (excluding the one-inch offtake piping, which is periodically replaced and not subject to aging management review), the attached nonsafety-related piping components to and including the vacuum priming tank that provide support for the attached safety-related components, and the tank drains to the circulating water condenser outlet pipes that support circulating water system integrity. Additionally, the vacuum priming pumps themselves and their seal water tanks, pumps, heat exchangers and piping, as well as the air offtake boxes, and the loop seals at the air ejector discharges and associated piping within the Turbine Building perform a leakage boundary function and are subject to aging management review. Vacuum priming piping components between the offtake control valves and the vacuum priming tank do not perform a leakage boundary function as this piping contains air and is normally under vacuum, such that a loss of integrity would not result in spatial interactions with safety-related components. Similarly, components in the air ejector discharge vent path other than loop seals do not perform a leakage boundary function as they contain only moist air and gas.

System Intended Functions

Portions of the vacuum priming system perform the following safety-related function: The system provides a pressure boundary for the service water system at the component cooling water heat exchangers. Therefore, the vacuum priming system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the vacuum priming system contain nonsafety-related components credited with pressure boundary integrity of the circulating water system to maintain Intake Canal level, and also contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the vacuum priming system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, and for spatial interaction and structural integrity.

Portions of the vacuum priming system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), and Station Blackout (10 CFR 50.63). Therefore, the vacuum priming system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3). However, the system function credited for these regulated events is to break vacuum in the system to interrupt the siphoning of water through the condenser. Passive component pressure boundary integrity is not required to support this function.

UFSAR References

Additional details of the vacuum priming system can be found in the UFSAR, Section 9.4.1.1, Section 10.3.4.2, and Section 10.3.4.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the vacuum priming system are listed below:

11448-SLRM-066A Sht 1

11448-SLRM-066A Sht 2

11448-SLRM-074A Sht 1

11548-SLRM-066A Sht 1

11548-SLRM-066A Sht 2

11548-SLRM-074A Sht 1

11548-SLRM-074A Sht 2

Components Subject to Aging Management Review

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

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

2.3.3.33 Containment Vacuum

System Description

The containment vacuum system establishes and maintains subatmospheric pressure in the Containment in support of plant operation. The containment vacuum system also provides a flowpath, via the containment penetration piping, for the containment post-accident hydrogen analyzers in the gaseous waste system.

System Evaluation Boundary

The evaluation boundary for the containment vacuum system components subject to aging management review includes the safety-related piping and valves associated with the containment penetrations for the vacuum ejector and the vacuum pumps, as well as connected nonsafety-related piping and components that provides support, and the air ejector and discharge piping that perform a leakage boundary function.

System Intended Functions

Portions of the containment vacuum system perform the following safety-related functions: The system provides containment integrity, provides a sample flowpath for the hydrogen analyzers, and includes safety-related instrumentation. Therefore, the containment vacuum system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the containment vacuum system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the containment vacuum 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.

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

UFSAR References

Additional details of the containment vacuum system can be found in the UFSAR, Section 5.3.4, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the containment vacuum system are listed below:

11448-SLRM-085A Sht 1

11448-SLRM-085A Sht 2

11548-SLRM-085A Sht 1

11548-SLRM-085A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-33, Containment Vacuum.

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

2.3.3.34 Fire Protection

System Description

The fire protection system provides for detection and suppression of fires such that plant equipment damage is minimized and safe shutdown of the plant can be achieved. The fire protection system also provides a back-up source of makeup or cooling water to various plant systems.

The fire protection system is comprised of fire and smoke detection components, water-based fire suppression components (including water tanks, fire pumps, distribution piping, valves, hose racks, hydrants, deluge and sprinkler systems), and gas-based fire suppression components (including carbon dioxide and halon distribution equipment).

Carbon dioxide suppression is provided for the switchgear rooms, the Service Building cable vaults, the Containment Cable Vaults, the cable tray rooms, the charcoal filter assemblies, the high and low pressure turbine bearing enclosures, the generator bearing enclosures, the three emergency diesel generator rooms, and the motor control center rooms.

Halon suppression is provided for the emergency switchgear and relay rooms, the Security Building under-floor area, and in the Training Center in the computer room of the simulator control room, the simulator area, and the computer room of the Local Emergency Operations Facility.

The fire protection system also includes the reactor coolant pump motor oil collection system components.

System Evaluation Boundary

The evaluation boundary for the fire protection system components subject to aging management review includes the fire water system storage tanks, pumps, yard piping, distribution piping and components associated with all sprinkler, spray and hose station suppression features within the protected area, as well as suppression piping to and within the Radwaste Facility and Station Blackout Building outside the protected area. Additional fire water piping outside the protected area connecting to the Radwaste Facility and Station Blackout Building supply branches is within-scope up to the next isolation valves. All of the carbon dioxide suppression systems, along with the halon suppression systems in the emergency switchgear and relay rooms are subject to aging management review. The Security Building sub-floor halon system and the halon systems in the Training Building are not within the scope of subsequent license renewal. The halon systems are not depicted on subsequent license renewal drawings.

The foundations for the fire protection and domestic water storage tanks are evaluated in the structural section of the subsequent license renewal application. Structural fire barriers such as fire doors, fire-retardant coatings, or fire seals are evaluated in the structural section.

System Intended Functions

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

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

UFSAR References

Additional details of the fire protection system can be found in the UFSAR, Section 9.10, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRB-047A Sht 1

11448-SLRB-047B Sht 1

11448-SLRB-047B Sht 2

11448-SLRB-047B Sht 3

11448-SLRB-047B Sht 4

11448-SLRB-047B Sht 5

11448-SLRB-047C Sht 1

11448-SLRB-047C Sht 3

11448-SLRB-047E Sht 1

11448-SLRB-047E Sht 2

11448-SLRB-047E Sht 3

11448-SLRB-047E Sht 4

11448-SLRB-047E Sht 5

11448-SLRB-047F Sht 1

11448-SLRB-047G Sht 1

11448-SLRB-047H Sht 1

11448-SLRB-047J Sht 1

11448-SLRB-047J1 Sht 1

11448-SLRB-047J2 Sht 1

11448-SLRB-047J3 Sht 1

11548-SLRB-047B Sht 1

11548-SLRB-047F Sht 1

LRD-00-1225-100 Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-34, Fire Protection.

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

2.3.3.35 Hydrogen Gas

System Description

The hydrogen gas system provides hydrogen and carbon dioxide gas for main electrical generator service.

The carbon dioxide supply used to purge the generators is provided from the fire protection system carbon dioxide tank. A carbon dioxide vaporizer (heat exchanger) uses steam heat from the heating steam system to warm the carbon dioxide prior to injection into the generators.

The hydrogen gas system includes connections to the main generators to provide for gas addition, venting, purging, gas monitoring, and detection of potential water leakage from the generator internal hydrogen coolers. The system also includes hydrogen gas dryers, gas dryer heat exchangers and moisture separators to maintain hydrogen purity.

System Evaluation Boundary

The evaluation boundary for the hydrogen gas system components subject to aging management review includes the hydrogen gas dryer heat exchangers and their associated moisture separators, drain traps and piping components, the main unit generator water detectors and their associated piping components, and the carbon dioxide vaporizer, all of which retain water or steam within buildings containing safety-related components. Additionally subject to aging management review is the valve that isolates the fire protection system carbon dioxide supply from the purge flowpath to the Unit 1 and Unit 2 main generators because it provides a pressure boundary for the fire protection carbon dioxide subsystem.

System Intended Functions

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

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

UFSAR References

Additional details of the hydrogen gas system can be found in the UFSAR, Section 10.3.3.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the hydrogen gas system are listed below:

11448-SLRB-047E Sht 1

11448-SLRM-151A Sht 1

11448-SLRM-151A Sht 2

11548-SLRM-151A Sht 1

11548-SLRM-151A Sht 2

Components Subject to Aging Management Review

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

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

2.3.3.36 Emergency Diesel Generator System

System Description

The emergency diesel generator is a diesel engine-driven electrical generator that provides a back-up source of electrical power to the emergency electrical bus in the event that the normal supply is unavailable. Each unit has a dedicated emergency diesel generator, and a third diesel generator is provided as a swing diesel and is shared by Units 1 and 2. The emergency diesel generator system consists of the diesel generators and associated fuel oil, starting air, lubricating oil, cooling water, intake and exhaust support subsystems.

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 oil pumps, fuel oil tanks and associated piping to the diesel injectors; the external passive, long-lived mechanical components in the lubricating oil, cooling water, intake and exhaust subsystems; the starting air subsystems from the start air tank supply check valves to the air tanks to the start air motors; as well as nonsafety-related components that provide leakage boundary or structural integrity. The engine, its internal components, and the electrical generator are active components and are not subject to aging management review.

System Intended Functions

Portions of the emergency diesel generator system perform the following safety-related functions: The system provides a reliable source of emergency power for safety-related loads and to establish and maintain safe shutdown. Therefore, the emergency diesel generator system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the emergency diesel generator system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the emergency diesel generator 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.

Portions of the emergency diesel generator system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the emergency diesel generator system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the emergency diesel generator system can be found in the UFSAR, Section 7.2.3.2.7, Section 8.5, and Section 10.3.5.3.

Subsequent License Renewal Boundary Drawings

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

11448-SLRB-038A Sht 1

11448-SLRB-038A Sht 2

11448-SLRB-038A Sht 4

11448-SLRB-046A Sht 1

11448-SLRB-046A Sht 2

11448-SLRB-046A Sht 3

11448-SLRB-046B Sht 1

11448-SLRB-046B Sht 2

11448-SLRB-046B Sht 3

11448-SLRB-046C Sht 1

11448-SLRB-046C Sht 2

11448-SLRB-046C Sht 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-36, Emergency Diesel Generator System.

The aging management review results for these component types are indicated in Table 3.3.2-36, Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation.

2.3.3.37 Alternate AC

System Description

The alternate AC system, installed in response to 10 CFR 50.63, provides AC power to one emergency electrical bus at each unit during a station blackout event. It also has the ability to provide power to the control room/emergency switchgear chillers in the event of a fire. The alternate AC system consists of the diesel generator and the associated fuel oil, starting air, lubricating oil, cooling water, intake and exhaust support systems.

System Evaluation Boundary

The evaluation boundary for the alternate AC system components subject to aging management review includes the external, long-lived, passive mechanical components of the intake and exhaust, cooling water, fuel oil, and lubricating oil subsystems, as well as starting air subsystem components from the start air compressor cooler and filter outlet check valve through the air receiver to the start air motors. The engine, its internal components, and the electrical generator are active components and are not subject to aging management review.

System Intended Functions

Portions of the alternate AC system perform the following safety related functions: The system contains safety-related electrical hand switches. Therefore, the alternate AC system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

UFSAR References

Additional details of the alternate AC system can be found in the UFSAR, Section 8.4.6.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the alternate AC system are listed below:

11448-SLRB-038B Sht 1

11448-SLRB-046D Sht 1

11448-SLRB-046D Sht 2

11448-SLRB-046D Sht 3

11448-SLRB-046D Sht 4

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-37, Alternate AC.

The aging management review results for these component types are indicated in Table 3.3.2-37, Auxiliary Systems - Alternate AC - Aging Management Evaluation.

2.3.3.38 Security

System Description

The security system provides the physical security features of the plant. In addition to components related to physical security, the system provides emergency lighting that supports access/egress during an Appendix R fire event. A diesel generator provides backup power for the system. The security system diesel generator consists of the diesel generator and associated fuel oil, lubricating oil, cooling water, intake and exhaust support subsystems.

System Evaluation Boundary

The evaluation boundary for the security system components subject to aging management review includes the external, passive, long-lived mechanical components of the back-up diesel-generator in the fuel oil, lubricating oil, cooling water, intake air and exhaust subsystems. The engine itself, its internal components, and the electrical generator are active components and are not subject to aging management review.

System Intended Functions

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

UFSAR References

Additional details of the security system can be found in the UFSAR, Section 8.4.5 and Section 8.4.6.

Subsequent License Renewal Boundary Drawings

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

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-38, Security.

The aging management review results for these component types are indicated in Table 3.3.2-38, Auxiliary Systems - Security - Aging Management Evaluation.

2.3.3.39 Buildings and Structures

System Description

The buildings and structures system includes structures, substructures and miscellaneous structural elements that have been assigned plant mark numbers, as well as a limited number of miscellaneous electrical and mechanical components not associated with other systems. Equipment hatch airlock test valves and piping are the only mechanical components in the system that are within the scope of subsequent license renewal, and allow for pressurization testing of the equipment hatch personnel airlocks.

System Evaluation Boundary

The evaluation boundary for the buildings and structures system components subject to aging management review includes only the equipment hatch personnel airlock test valves and associated piping components. The structures and structural elements within the system are evaluated in the structural section of the SLRA.

System Intended Functions

Portions of the buildings and structures system perform the following safety-related functions: The system provides containment integrity. Therefore, the buildings and structures system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the buildings and structures system can be found in the UFSAR, Section 15.5.1.8.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the buildings and structures system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-39, Buildings and Structures.

The aging management review results for these component types are indicated in Table 3.3.2-39, Auxiliary Systems - Buildings and Structures - Aging Management Evaluation.

2.3.3.40 Containment Access

System Description

The containment access system uses hydraulic fluid pumps and actuators to operate the containment personnel airlock locking devices. The system normally operates the locking mechanism using electrically driven hydraulic pump/actuator drives, but a hand pump may be used if the electric pumps are unavailable.

System Evaluation Boundary

The evaluation boundary for the containment access system components subject to aging management review includes pump casings, actuator bodies and piping components that retain oil in buildings containing safety-related components.

System Intended Functions

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

UFSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the containment access system are listed below:

11448-SLRM-091C Sht 1

11548-SLRM-091C Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-40, Containment Access.

The aging management review results for these component types are indicated in Table 3.3.2-40, Auxiliary Systems - Containment Access - Aging Management Evaluation.

2.3.3.41 Electrical Power

System Description

The electrical power system provides for power transmission between the station and the switchyard and for power distribution within the station. The system primarily encompasses electrical components, but includes the exciter air coolers, which are the only mechanical components in the system that are subject to aging management review.

System Evaluation Boundary

The evaluation boundary for the electrical power system components subject to aging management review includes only the main generator exciter air coolers that retain water in buildings containing safety-related components. There are no mechanical components within the electrical power system that support safety-related or regulated event functions.

System Intended Functions

Portions of the electrical power system perform the following safety-related functions: The system provides power to safety-related components and contains safety-related instrumentation. Therefore, the electrical power system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1). However, no mechanical components within the system support these safety-related functions.

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

Portions of the electrical power system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transient Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the electrical power system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3). However, no mechanical components within the system support these regulated event functions.

UFSAR References

Additional details of the electrical power system can be found in the UFSAR, Section 8.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the electrical power system are listed below:

11448-SLRM-073A Sht 1

11548-SLRM-073A Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-41, Electrical Power.

The aging management review results for these component types are indicated in Table 3.3.2-41, Auxiliary Systems - Electrical Power - Aging Management Evaluation.

2.3.3.42 Helium Vacuum Drying

System Description

The helium vacuum drying system supports dewatering and vacuum drying of the fuel storage dry shielded canisters, followed by backfilling the casks with helium.

System Evaluation Boundary

The evaluation boundary for the helium vacuum drying system components subject to aging management review includes the nonsafety-related dry shielded canister reflood pump and piping components that retain water in buildings containing safety-related components.

System Intended Functions

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

UFSAR References

Additional details of the helium vacuum drying system can be found in the UFSAR, Section 9.14.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the helium vacuum drying system are listed below:

11448-SLRM-153A Sht 1

11448-SLRM-153B Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-42, Helium Vacuum Drying.

The aging management review results for these component types are indicated in Table 3.3.2-42, Auxiliary Systems - Helium Vacuum Drying - Aging Management Evaluation.

2.3.3.43 Reactor Building Penetrations

System Description

The reactor building penetration system provides penetrations through Containment for electrical and mechanical systems while maintaining containment integrity.

System Evaluation Boundary

The evaluation boundary for the reactor building penetration system components subject to aging management review includes only the electrical penetration test piping and valves.

The penetration assemblies themselves are evaluated as structural commodities. The electrical cables associated with electrical penetrations are evaluated in the electrical section, and the mechanical system piping that passes through mechanical penetrations is evaluated with the applicable mechanical system.

System Intended Functions

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

Portions of the reactor building penetration system are relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the reactor building penetration system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the reactor building penetrations system can be found in the UFSAR, Section 5.5.

Subsequent License Renewal Boundary Drawings

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

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-43, Reactor Building Penetrations.

The aging management review results for these component types are indicated in Table 3.3.2-43, Auxiliary Systems - Reactor Building Penetrations - Aging Management Evaluation.

Intentionally Blank

Screening Results Tables: Auxiliary Systems

Table 2.3.3-1 Fuel Handling

Component Type	Intended Function(s)
Blind flange (fuel transfer tube)	Pressure Boundary
Bolting	Pressure Boundary
Expansion joint	Pressure Boundary
Fuel transfer tube	Pressure Boundary
Fuel transfer tube enclosure	Pressure Boundary
Valve body	Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-1, Auxiliary Systems - Fuel Handling - Aging Management Evaluation.

Table 2.3.3-2 Fuel Pool Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Demineralizer (fuel pit ion exchanger - shell)	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (fuel pit cooler - channel)	Pressure Boundary
Heat exchanger (fuel pit cooler - shell)	Pressure Boundary
Heat exchanger (fuel pit cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (fuel pit cooler - tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (spent fuel pit pump)	Pressure Boundary
Pump casing (spent fuel pit purification pump)	Leakage Boundary (Spatial)
Pump casing (spent fuel pit skimmer pump)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-2, Auxiliary Systems - Fuel Pool Cooling - Aging Management Evaluation.

Table 2.3.3-3 Cranes and Hoists

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

The AMR results for these component types are indicated in Table 3.3.2-3, Auxiliary Systems - Cranes and Hoists - Aging Management Evaluation.

Table 2.3.3-4 Service Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Catch basin	Leakage Boundary (Spatial)
Expansion joint	Pressure Boundary
Flexible hose	Pressure Boundary
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (charging pump service water)	Pressure Boundary
Pump casing (chemical injection skid)	Leakage Boundary (Spatial)
Pump casing (chemical metering)	Leakage Boundary (Spatial)
Pump casing (emergency service water)	Pressure Boundary
Pump casing (recirculation spray heat exchanger service water radiation monitor)	Pressure Boundary
Pump casing (river water make-up)	Leakage Boundary (Spatial)
Separator	Pressure Boundary
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Spray shield	Flood Barrier

Table 2.3.3-4 Service Water

Component Type	Intended Function(s)
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Strainer element	Filtration
Tank (brominator mixing)	Leakage Boundary (Spatial)
Tank (diesel fuel oil)	Pressure Boundary
Tank (pump pulsation dampener)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-4, Auxiliary Systems - Service Water - Aging Management Evaluation.

Table 2.3.3-5 Circulating Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Pressure Boundary
Heat exchanger (circulating water condenser - channel head)	Pressure Boundary
Heat exchanger (circulating water condenser - tube)	Pressure Boundary
Heat exchanger (circulating water condenser - tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Spray shield	Flood Barrier
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-5, Auxiliary Systems - Circulating Water - Aging Management Evaluation.

Table 2.3.3-6 Bearing Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flexible connection	Leakage Boundary (Spatial)
Flow restrictor	Leakage Boundary (Spatial)
Heat exchanger (bearing cooling - channel)	Leakage Boundary (Spatial)
Heat exchanger (bearing cooling - shell)	Leakage Boundary (Spatial)
Heat exchanger (isophase bus duct - header)	Leakage Boundary (Spatial)
Heat exchanger (isophase bus duct - tube)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (bearing cooling)	Leakage Boundary (Spatial)
Pump casing (chemical injection)	Leakage Boundary (Spatial)
Pump casing (makeup)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (air conditioner head)	Leakage Boundary (Spatial), Pressure Boundary
Tank (chemical addition)	Leakage Boundary (Spatial)

Table 2.3.3-6 Bearing Cooling

Component Type	Intended Function(s)
Tank (chemical injection)	Leakage Boundary (Spatial)
Tank (head)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-6, Auxiliary Systems - Bearing Cooling - Aging Management Evaluation.

Table 2.3.3-7 Chilled Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Structural Integrity (Attached)
Filter housing (chiller oil)	Leakage Boundary (Spatial)
Heat exchanger (chilled component cooling - channel)	Leakage Boundary (Spatial)
Heat exchanger (chilled component cooling - shell)	Leakage Boundary (Spatial)
Heat exchanger (chiller - channel)	Leakage Boundary (Spatial)
Heat exchanger (chiller oil - channel)	Leakage Boundary (Spatial)
Heat exchanger (condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (refueling water storage tank - channel)	Structural Integrity (Attached)
Heat exchanger (refueling water storage tank - shell)	Structural Integrity (Attached)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (chilled component cooling)	Leakage Boundary (Spatial)
Pump casing (chilled water circulating)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Tank (chiller oil separator)	Leakage Boundary (Spatial)
Tank (flash)	Leakage Boundary (Spatial)

Table 2.3.3-7 Chilled Water

Component Type	Intended Function(s)
Tank (surge)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The AMR results for these component types are indicated in Table 3.3.2-7, Auxiliary Systems - Chilled Water - Aging Management Evaluation.

Table 2.3.3-8 Component Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Pressure Boundary
Filter housing	Pressure Boundary
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 (containment penetration jacket)	Heat Transfer, Pressure Boundary
Heat exchanger (shield penetration jacket)	Heat Transfer, Pressure Boundary
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (component cooling)	Pressure Boundary
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Strainer body	Leakage Boundary (Spatial), Pressure Boundary

Table 2.3.3-8 Component Cooling

Component Type	Intended Function(s)
Tank (air accumulator)	Pressure Boundary
Tank (charging pump seal cooling surge)	Leakage Boundary (Spatial), Pressure Boundary
Tank (chemical addition)	Leakage Boundary (Spatial)
Tank (surge)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

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

Table 2.3.3-9 Neutron Shield Tank Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (shield tank cooler - channel)	Pressure Boundary
Heat exchanger (shield tank cooler - shell)	Pressure Boundary
Heat exchanger (shield tank cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (shield tank cooler - tubesheet)	Pressure Boundary
Heat exchanger (shield wall panel)	Heat Transfer, Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Tank (corrosion control)	Leakage Boundary (Spatial)
Tank (surge)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-9, Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation.

Table 2.3.3-10 Primary Grade Water

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

The AMR results for these component types are indicated in Table 3.3.2-10, Auxiliary Systems - Primary Grade Water - Aging Management Evaluation.

Table 2.3.3-11 Instrument Air

Component Type	Intended Function(s)
Blocking device (stored)	Flow Distribution
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Compressor housing	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Flexible hose	Leakage Boundary (Spatial), Pressure Boundary
Flexible hose (stored)	Pressure Boundary
Heat exchanger (air compressor oil channel)	Leakage Boundary (Spatial)
Heat exchanger (air compressor oil tube)	Leakage Boundary (Spatial)
Heat exchanger (air compressor seal water channel)	Pressure Boundary
Heat exchanger (air compressor seal water shell)	Pressure Boundary
Heat exchanger (air compressor seal water tube)	Pressure Boundary
Heat exchanger (air compressor seal water tubesheet)	Pressure Boundary
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (air compressor oil)	Leakage Boundary (Spatial)

Table 2.3.3-11 Instrument Air

Component Type	Intended Function(s)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (air compressor moisture separator)	Leakage Boundary (Spatial)
Tank (backup air cylinder)	Pressure Boundary
Tank (containment air receiver)	Structural Integrity (Attached)
Tank (stored gas bottle)	Pressure Boundary
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Valve body (stored)	Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-11, Auxiliary Systems - Instrument Air - Aging Management Evaluation.

Table 2.3.3-12 Primary and Secondary Plant Gas Supply

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (steam generator vacuum pump)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (vacuum pump separator)	Leakage Boundary (Spatial)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-12, Auxiliary Systems - Primary and Secondary Plant Gas Supply - Aging Management Evaluation.

Table 2.3.3-13 Service Air

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

The AMR results for these component types are indicated in Table 3.3.2-13, Auxiliary Systems - Service Air - Aging Management Evaluation.

Table 2.3.3-14 Boron Recovery

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (bottoms cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (bottoms cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (distillate cooler - channel)	Pressure Boundary
Heat exchanger (distillate cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (distillate cooler - tube and tubesheet)	Pressure Boundary
Heat exchanger (drain tank pump jacket cooler)	Pressure Boundary
Heat exchanger (electric heater - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator reboiler - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator reboiler - shell)	Leakage Boundary (Spatial)
Heat exchanger (overhead condenser - channel)	Pressure Boundary
Heat exchanger (overhead condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (overhead condenser - tube and tubesheet)	Pressure Boundary

Table 2.3.3-14 Boron Recovery

Component Type	Intended Function(s)
Heat exchanger (overhead gas compressor - cooling jacket)	Pressure Boundary
Heat exchanger (primary drain tank vent chiller condenser - channel)	Pressure Boundary
Heat exchanger (primary drain tank vent chiller condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (primary drain tank vent chiller condenser - tube and tubesheet)	Pressure Boundary
Heat exchanger (stripper feed - channel head)	Leakage Boundary (Spatial)
Heat exchanger (stripper feed - shell)	Leakage Boundary (Spatial)
Heat exchanger (stripper feed - tube and tubesheet)	Leakage Boundary (Spatial)
Heat exchanger (stripper feed stream heater - channel)	Leakage Boundary (Spatial)
Heat exchanger (stripper feed stream heater - shell)	Leakage Boundary (Spatial)
Heat exchanger (stripper feed stream heater - tube and tubesheet)	Leakage Boundary (Spatial)
Heat exchanger (stripper overhead condenser - channel)	Pressure Boundary
Heat exchanger (stripper overhead condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (stripper overhead condenser - tube and tubesheet)	Pressure Boundary
Heat exchanger (stripper trim cooler - channel)	Leakage Boundary (Spatial)

Table 2.3.3-14 Boron Recovery

Component Type	Intended Function(s)
Heat exchanger (stripper trim cooler - shell)	Pressure Boundary
Heat exchanger (stripper trim cooler - tube and tubesheet)	Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (evaporator bottoms cooler)	Leakage Boundary (Spatial)
Pump casing (evaporator bottoms tank)	Leakage Boundary (Spatial)
Pump casing (evaporator bottoms)	Leakage Boundary (Spatial)
Pump casing (evaporator circulating)	Leakage Boundary (Spatial)
Pump casing (evaporator distillate)	Leakage Boundary (Spatial)
Pump casing (primary drain tank)	Leakage Boundary (Spatial)
Pump casing (stripper circulating)	Leakage Boundary (Spatial)
Pump casing (test tank)	Leakage Boundary (Spatial)
Pump casing (waste bottoms)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (boron cleanup ion exchanger)	Leakage Boundary (Spatial)
Tank (cesium removal ion exchanger)	Leakage Boundary (Spatial)
Tank (distillate accumulator)	Leakage Boundary (Spatial)
Tank (evaporator bottoms tank)	Leakage Boundary (Spatial)

Table 2.3.3-14 Boron Recovery

Component Type	Intended Function(s)
Tank (evaporator tank A - bottoms and tower)	Leakage Boundary (Spatial)
Tank (evaporator tank B - bottoms)	Leakage Boundary (Spatial)
Tank (evaporator tank B - tower)	Leakage Boundary (Spatial)
Tank (gas stripper surge)	Pressure Boundary
Tank (gas stripper)	Leakage Boundary (Spatial)
Tank (primary drain tank)	Pressure Boundary
Tank (sample cylinder)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-14, Auxiliary Systems - Boron Recovery - Aging Management Evaluation.

Table 2.3.3-15 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
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (batch tank jacket heater)	Leakage Boundary (Spatial)
Heat exchanger (charging pump oil cooler - channel)	Pressure Boundary
Heat exchanger (charging pump oil cooler - shell)	Pressure Boundary
Heat exchanger (charging pump oil cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (charging pump oil cooler - tubesheet)	Pressure Boundary
Heat exchanger (charging pump seal cooler - case and cover)	Pressure Boundary
Heat exchanger (charging pump seal cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (excess letdown - channel)	Pressure Boundary
Heat exchanger (excess letdown - shell)	Pressure Boundary
Heat exchanger (excess letdown - tube)	Heat Transfer, Pressure Boundary

Table 2.3.3-15 Chemical and Volume Control

Component Type	Intended Function(s)
Heat exchanger (excess letdown - tubesheet)	Pressure Boundary
Heat exchanger (nonregenerative - channel)	Pressure Boundary
Heat exchanger (nonregenerative - shell)	Pressure Boundary
Heat exchanger (nonregenerative - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (nonregenerative - 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
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (boric acid)	Pressure Boundary

Table 2.3.3-15 Chemical and Volume Control

Component Type	Intended Function(s)
Pump casing (charging pump oil)	Pressure Boundary
Pump casing (charging)	Pressure Boundary
Pump casing (zinc injection)	Leakage Boundary (Spatial)
Strainer body	Pressure Boundary
Strainer element	Filtration
Tank (boric acid batch)	Leakage Boundary (Spatial)
Tank (boric acid)	Pressure Boundary
Tank (charging pump oil)	Pressure Boundary
Tank (chemical mixing)	Leakage Boundary (Spatial)
Tank (resin fill)	Leakage Boundary (Spatial)
Tank (volume control)	Pressure Boundary
Tank (zinc addition)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-15, Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation.

Table 2.3.3-16 Incore Instrumentation

Component Type	Intended Function(s)
Valve body	Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-16, Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation.

Table 2.3.3-17 Reactor Cavity Purification

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (purification)	Leakage Boundary (Spatial)
Pump casing (skimmer)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-17, Auxiliary Systems - Reactor Cavity Purification - Aging Management Evaluation.

Table 2.3.3-18 Sampling System

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Demineralizer shell	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Heat exchanger (sample chiller - shell/channel)	Leakage Boundary (Spatial)
Heat exchanger (sample cooler - heliflow shell)	Leakage Boundary (Spatial)
Heat exchanger (water bath - coils)	Leakage Boundary (Spatial)
Heat exchanger (water bath - tank)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (flushing)	Leakage Boundary (Spatial)
Pump casing (gas strip evacuating)	Leakage Boundary (Spatial)
Pump casing (high radiation sample waste)	Leakage Boundary (Spatial)
Pump casing (water bath cooling)	Leakage Boundary (Spatial)
Sample sink	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)

Table 2.3.3-18 Sampling System

Component Type	Intended Function(s)
Sight glass (body)	Leakage Boundary (Spatial)
Tank (high radiation sample waste)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-18, Auxiliary Systems - Sampling System - Aging Management Evaluation.

Table 2.3.3-19 Decontamination

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

The AMR results for these component types are indicated in Table 3.3.2-19, Auxiliary Systems - Decontamination - Aging Management Evaluation.

Table 2.3.3-20 Drains Aerated

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (auxiliary building sump pump)	Leakage Boundary (Spatial)
Pump casing (auxiliary building to turbine building pipe tunnel sump pump)	Leakage Boundary (Spatial)
Pump casing (component cooling heat exchanger pit sump pump)	Leakage Boundary (Spatial)
Pump casing (containment instrument air compressor room sump pump)	Leakage Boundary (Spatial)
Pump casing (fuel building sump pump)	Leakage Boundary (Spatial)
Pump casing (incore instrumentation room sump pump)	Leakage Boundary (Spatial)
Pump casing (reactor containment sump pump)	Leakage Boundary (Spatial)
Pump casing (reactor containment sump sample pump)	Leakage Boundary (Spatial)
Pump casing (safeguards area sump pump)	Leakage Boundary (Spatial)
Pump casing (safeguards valve pit sump pump)	Leakage Boundary (Spatial)

Table 2.3.3-20 Drains Aerated

Component Type	Intended Function(s)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Tank (primary vent pot)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-20, Auxiliary Systems - Drains Aerated - Aging Management Evaluation.

Table 2.3.3-21 Drains Gaseous

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (primary drain transfer tank cooler - channel)	Pressure Boundary
Heat exchanger (primary drain transfer tank cooler - shell)	Pressure Boundary
Heat exchanger (primary drain transfer tank cooler - tube)	Pressure Boundary
Heat exchanger (primary drain transfer tank cooler - tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (primary drain transfer pump)	Leakage Boundary (Spatial)
Tank (primary drain transfer tank)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-21, Auxiliary Systems - Drains Gaseous - Aging Management Evaluation.

Table 2.3.3-22 Gaseous Waste

Component Type	Intended Function(s)
Blower (waste gas purge)	Structural Integrity (Attached)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Gas compressor (head)	Pressure Boundary
Heat exchanger (constant temperature bath - shell)	Leakage Boundary (Spatial)
Heat exchanger (recombiner aftercooler - shell)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Tank (gas collection)	Leakage Boundary (Spatial)
Tank (moisture separator)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-22, Auxiliary Systems - Gaseous Waste - Aging Management Evaluation.

Table 2.3.3-23 Liquid and Solid Waste

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (contaminated drains transfer pumps recirc cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator - shell, head)	Leakage Boundary (Spatial)
Heat exchanger (evaporator bottoms cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator bottoms cooler - tube)	Leakage Boundary (Spatial)
Heat exchanger (evaporator distillate condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator distillate condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator distillate condenser - tube, tubesheet)	Leakage Boundary (Spatial)
Heat exchanger (evaporator distillate cooler - shell)	Pressure Boundary
Heat exchanger (evaporator distillate cooler - tube)	Pressure Boundary
Heat exchanger (evaporator reboiler - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator reboiler - tube)	Leakage Boundary (Spatial)

Table 2.3.3-23 Liquid and Solid Waste

Component Type	Intended Function(s)
Heat exchanger (evaporator reboiler - tubesheet)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Structural Integrity (Attached)
Pump casing (contaminated drains transfer pump)	Leakage Boundary (Spatial)
Pump casing (distillate pump)	Leakage Boundary (Spatial)
Pump casing (high level waste drain pump)	Leakage Boundary (Spatial)
Pump casing (laboratory waste drain tank pump)	Leakage Boundary (Spatial)
Pump casing (low level waste drain pump)	Leakage Boundary (Spatial)
Pump casing (waste disposal evaporator bottoms cooler pump)	Leakage Boundary (Spatial)
Pump casing (waste disposal evaporator bottoms pump)	Leakage Boundary (Spatial)
Pump casing (waste disposal evaporator circulating pump)	Leakage Boundary (Spatial)
Pump casing (waste disposal evaporator test tank pump)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Tank (contaminated drain tank)	Leakage Boundary (Spatial)
Tank (distillate tank)	Leakage Boundary (Spatial)
Tank (high level waste drain tank)	Leakage Boundary (Spatial)

Table 2.3.3-23 Liquid and Solid Waste

Component Type	Intended Function(s)
Tank (laboratory waste drain tank)	Leakage Boundary (Spatial)
Tank (liquid waste evaporator test tank)	Leakage Boundary (Spatial)
Tank (low level waste drain tank)	Leakage Boundary (Spatial)
Tank (spent resin blend)	Structural Integrity (Attached)
Tank (spent resin catch)	Structural Integrity (Attached)
Tank (waste disposal evaporator distillate demineralizer)	Leakage Boundary (Spatial)
Tank (waste disposal test tank)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-23, Auxiliary Systems - Liquid and Solid Waste - Aging Management Evaluation.

Table 2.3.3-24 Plumbing

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flexible hose	Pressure Boundary
Grating (storm drain)	Filtration
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (storm drain)	Flow Distribution
Pump casing (containment sub-surface drain pump)	Pressure Boundary
Pump casing (drain pump - service building)	Leakage Boundary (Spatial)
Pump casing (sewage ejection transfer pump)	Leakage Boundary (Spatial)
Pump casing (sump pump - Amertap pit)	Leakage Boundary (Spatial)
Pump casing (sump pump - ductline)	Pressure Boundary
Pump casing (sump pump - electrical manhole)	Leakage Boundary (Spatial)
Pump casing (sump pump - turbine building)	Pressure Boundary
Pump casing (turbine building sub-surface drain pump)	Leakage Boundary (Spatial)
Tank (air and vacuum sewer valve tank)	Leakage Boundary (Spatial)
Tank (sewage tank)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-24, Auxiliary Systems - Plumbing - Aging Management Evaluation.

Table 2.3.3-25 Radiation Monitoring

Component Type	Intended Function(s)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Filter housing	Structural Integrity (Attached)
Flow element	Structural Integrity (Attached)
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Pump casing (particulate and gas sampler air pump)	Structural Integrity (Attached)
Radiation sampler	Structural Integrity (Attached)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-25, Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation.

Table 2.3.3-26 Vents Aerated

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Tank (knockout drum)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-26, Auxiliary Systems - Vents Aerated - Aging Management Evaluation.

Table 2.3.3-27 Vents Gaseous

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

The AMR results for these component types are indicated in Table 3.3.2-27, Auxiliary Systems - Vents Gaseous - Aging Management Evaluation.

Table 2.3.3-28 Water Treatment

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Demineralizer (flash evaporator - shell)	Leakage Boundary (Spatial)
Filter housing (chiller supply)	Leakage Boundary (Spatial)
Filter housing (demineralizer postfilter)	Leakage Boundary (Spatial)
Filter housing (demineralizer prefilter)	Leakage Boundary (Spatial)
Filter housing (laboratory tank vent filter)	Leakage Boundary (Spatial)
Filter housing (laboratory water filter)	Leakage Boundary (Spatial)
Filter housing (water heater supply)	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (flash evaporator - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (chemical addition)	Leakage Boundary (Spatial)
Pump casing (chemical metering)	Leakage Boundary (Spatial)
Pump casing (clean water booster)	Leakage Boundary (Spatial)
Pump casing (condensate polisher regeneration)	Leakage Boundary (Spatial)
Pump casing (cyclohexylamine)	Leakage Boundary (Spatial)
Pump casing (demineralizer waste sump)	Leakage Boundary (Spatial)

Table 2.3.3-28 Water Treatment

Component Type	Intended Function(s)
Pump casing (flash evaporator distillate)	Leakage Boundary (Spatial)
Pump casing (flash evaporator makeup)	Leakage Boundary (Spatial)
Pump casing (flash evaporator recycle)	Leakage Boundary (Spatial)
Pump casing (hot water recirculating)	Leakage Boundary (Spatial)
Pump casing (phosphate)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (air chamber)	Leakage Boundary (Spatial)
Tank (ammonia hydroxide)	Leakage Boundary (Spatial)
Tank (chemical addition)	Leakage Boundary (Spatial)
Tank (cyclohexylamine)	Leakage Boundary (Spatial)
Tank (head)	Leakage Boundary (Spatial)
Tank (hot water)	Leakage Boundary (Spatial)
Tank (laboratory demineralizer)	Leakage Boundary (Spatial)
Tank (make-up pump head)	Leakage Boundary (Spatial)
Tank (phosphate)	Leakage Boundary (Spatial)
Tank (relief)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The AMR results for these component types are indicated in Table 3.3.2-28, Auxiliary Systems - Water Treatment - Aging Management Evaluation.

Table 2.3.3-29 Ventilation

Component Type	Intended Function(s)
Air handling unit (fin)	Heat Transfer
Air handling unit (header)	Leakage Boundary (Spatial), Pressure Boundary
Air handling unit (housing)	Pressure Boundary
Air handling unit (nonsafety-related tube)	Leakage Boundary (Spatial)
Air handling unit (safety-related tube)	Heat Transfer, Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Bolting (HVAC)	Pressure Boundary, Structural Integrity (Attached)
Compressor (chiller gas)	Pressure Boundary
Cooling coils (containment air recirculation - channel)	Pressure Boundary
Cooling coils (containment air recirculation - fin)	Heat Transfer
Cooling coils (containment air recirculation - housing)	Pressure Boundary
Cooling coils (containment air recirculation - tube)	Heat Transfer, Pressure Boundary
Cooling coils (reactor shroud - channel)	Pressure Boundary
Cooling coils (reactor shroud - fin)	Heat Transfer
Cooling coils (reactor shroud - housing)	Pressure Boundary
Cooling coils (reactor shroud - tube)	Heat Transfer, Pressure Boundary

Table 2.3.3-29 Ventilation

Component Type	Intended Function(s)
Damper housing	Pressure Boundary, Structural Integrity (Attached)
Drip pan	Leakage Boundary (Spatial)
Ducting	Fire Barrier, Pressure Boundary, Structural Integrity (Attached)
Fan housing	Pressure Boundary, Structural Integrity (Attached)
Filter housing	Pressure Boundary, Structural Integrity (Attached)
Fire damper (housing)	Fire Barrier, Pressure Boundary
Flexible connection	Pressure Boundary
Flexible hose (Appendix R temporary ducting)	Pressure Boundary
Heat exchanger (central chilled water condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (central chilled water evaporator - shell)	Leakage Boundary (Spatial)
Heat exchanger (control room chilled water condenser - channel)	Pressure Boundary
Heat exchanger (control room chilled water condenser - shell)	Pressure Boundary
Heat exchanger (control room chilled water condenser - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (control room chilled water condenser - tubesheet)	Pressure Boundary
Heat exchanger (control room chilled water evaporator - channel)	Pressure Boundary

Table 2.3.3-29 Ventilation

Component Type	Intended Function(s)
Heat exchanger (control room chilled water evaporator - shell)	Pressure Boundary
Heat exchanger (control room chilled water evaporator - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (control room chilled water evaporator - tubesheet)	Pressure Boundary
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (central chilled water pump)	Leakage Boundary (Spatial)
Pump casing (chiller oil)	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (control room chilled water)	Pressure Boundary
Pump casing (control room chiller service water)	Pressure Boundary
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Strainer element	Filtration
Tank (air bottle)	Pressure Boundary
Tank (control room chilled water surge)	Pressure Boundary
Tank (control room chilled water surge - bladder)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-29, Auxiliary Systems - Ventilation - Aging Management Evaluation.

Table 2.3.3-30 Leakage Monitoring

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

The AMR results for these component types are indicated in Table 3.3.2-30, Auxiliary Systems - Leakage Monitoring - Aging Management Evaluation.

Table 2.3.3-31 Secondary Vents

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

The AMR results for these component types are indicated in Table 3.3.2-31, Auxiliary Systems - Secondary Vents - Aging Management Evaluation.

Table 2.3.3-32 Vacuum Priming

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Heat exchanger (seal water - channel)	Leakage Boundary (Spatial)
Heat exchanger (seal water - shell)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (seal water)	Leakage Boundary (Spatial)
Pump casing (vacuum priming)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (offtake)	Leakage Boundary (Spatial)
Tank (separator)	Leakage Boundary (Spatial)
Tank (vacuum priming)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-32, Auxiliary Systems - Vacuum Priming - Aging Management Evaluation.

Table 2.3.3-33 Containment Vacuum

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Tank (vacuum pump)	Structural Integrity (Attached)
Vacuum ejector	Leakage Boundary (Spatial)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The AMR results for these component types are indicated in Table 3.3.2-33, Auxiliary Systems - Containment Vacuum - Aging Management Evaluation.

Table 2.3.3-34 Fire Protection

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Compressor housing (hydropneumatic tank)	Pressure Boundary
Drip pan and enclosures (reactor coolant pump oil collection)	Pressure Boundary
Exhaust silencer	Pressure Boundary
Expansion joint	Pressure Boundary
Fire hydrant	Pressure Boundary
Flame arrestor	Pressure Boundary
Flexible connector	Pressure Boundary
Hose rack (fittings)	Pressure Boundary
Nozzle	Spray Pattern
Odorizer	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Pressure Boundary
Pump casing (diesel fuel)	Pressure Boundary
Pump casing (fire pump)	Pressure Boundary
Pump casing (pressure maintenance)	Pressure Boundary
Sight glass	Pressure Boundary
Sight glass (reactor coolant pump oil collection - plexiglass)	Pressure Boundary
Sight glass body	Pressure Boundary

Table 2.3.3-34 Fire Protection

Component Type	Intended Function(s)
Sprinkler head	Spray Pattern
Strainer body	Pressure Boundary
Strainer body (deluge/alarm check trim)	Pressure Boundary
Strainer element	Filtration
Strainer element (deluge/alarm check trim)	Filtration
Tank (carbon dioxide)	Pressure Boundary
Tank (fire protection and domestic water storage)	Pressure Boundary
Tank (fuel oil)	Pressure Boundary
Tank (halon)	Pressure Boundary
Tank (hydropneumatic)	Pressure Boundary
Tank (reactor coolant pump oil collection)	Pressure Boundary
Tank (retarding chamber)	Pressure Boundary
Valve body	Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-34, Auxiliary Systems - Fire Protection - Aging Management Evaluation.

Table 2.3.3-35 Hydrogen Gas

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (carbon dioxide vaporizer - channel / tubesheet)	Leakage Boundary (Spatial)
Heat exchanger (carbon dioxide vaporizer - tube)	Leakage Boundary (Spatial)
Heat exchanger (gas dryer - shell)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Tank (moisture separator)	Leakage Boundary (Spatial)
Tank (water detector)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-35, Auxiliary Systems - Hydrogen Gas - Aging Management Evaluation.

Table 2.3.3-36 Emergency Diesel Generator System

Component Type	Intended Function(s)
Air dryer	Leakage Boundary (Spatial)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Drip pan	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial), Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (aftercooler - channel)	Pressure Boundary
Heat exchanger (aftercooler - fin)	Heat Transfer
Heat exchanger (aftercooler - shell)	Pressure Boundary
Heat exchanger (aftercooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (aftercooler - tubesheet)	Pressure Boundary
Heat exchanger (air start aftercooler - tube)	Leakage Boundary (Spatial)
Heat exchanger (immersion heater)	Pressure Boundary
Heat exchanger (lube oil - channel)	Pressure Boundary
Heat exchanger (lube oil - shell)	Pressure Boundary
Heat exchanger (radiator - header)	Pressure Boundary
Heat exchanger (radiator - tube)	Heat Transfer, Pressure Boundary
Lubricator body	Pressure Boundary
Motor casing (air start motor)	Pressure Boundary

Table 2.3.3-36 Emergency Diesel Generator System

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)	Pressure Boundary
Pump casing (fuel tank level bubbler hand pump)	Pressure Boundary
Pump casing (jacket cooling)	Pressure Boundary
Pump casing (lube oil)	Pressure Boundary
Rupture disc	Pressure Boundary
Sight glass	Pressure Boundary
Sight glass (body)	Pressure Boundary
Silencer (exhaust)	Pressure Boundary
Strainer body	Pressure Boundary
Strainer element	Filtration
Tank (fuel oil, auxiliary)	Pressure Boundary
Tank (fuel oil, base)	Pressure Boundary
Tank (fuel oil, buried)	Pressure Boundary
Tank (jacket cooling expansion)	Pressure Boundary
Tank (starting air)	Pressure Boundary
Turbocharger housing (compressor)	Pressure Boundary
Turbocharger housing (turbine)	Pressure Boundary

Table 2.3.3-36 Emergency Diesel Generator System

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

The AMR results for these component types are indicated in Table 3.3.2-36, Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation.

Table 2.3.3-37 Alternate AC

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Expansion joint	Pressure Boundary
Filter housing	Pressure Boundary
Filter housing (head)	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (aftercooler - channel)	Pressure Boundary
Heat exchanger (aftercooler - shell)	Pressure Boundary
Heat exchanger (aftercooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (aftercooler - tubesheet)	Pressure Boundary
Heat exchanger (cooling water and fuel oil radiators - fin)	Heat Transfer
Heat exchanger (cooling water and fuel oil radiators - header)	Pressure Boundary
Heat exchanger (cooling water and fuel oil radiators - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (lube oil - channel)	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 (jacket water)	Pressure Boundary
Heater housing (lubricating oil)	Pressure Boundary

Table 2.3.3-37 Alternate AC

Component Type	Intended Function(s)
Lubricator body	Pressure Boundary
Motor casing (air start motor)	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Pressure Boundary
Pump casing (fuel transfer)	Pressure Boundary
Pump casing (jacket water)	Pressure Boundary
Pump casing (lube oil)	Pressure Boundary
Sight glass	Pressure Boundary
Sight glass (body)	Pressure Boundary
Silencer	Pressure Boundary
Tank (fuel oil)	Pressure Boundary
Tank (fuel rack shutoff air tank)	Pressure Boundary
Tank (jacket water expansion)	Pressure Boundary
Tank (oil sump)	Pressure Boundary
Tank (start air receiver)	Pressure Boundary
Turbocharger (compressor)	Pressure Boundary
Turbocharger (turbine)	Pressure Boundary
Valve body	Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-37, Auxiliary Systems - Alternate AC - Aging Management Evaluation.

Table 2.3.3-38 Security

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Filter housing (intake air)	Pressure Boundary
Flexible connection (radiator exhaust)	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (lube oil - channel)	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
Heat exchanger (radiator fin)	Heat Transfer
Heat exchanger (radiator header)	Pressure Boundary
Heat exchanger (radiator tube)	Heat Transfer, Pressure Boundary
Heater housing (coolant)	Pressure Boundary
Piping, piping components	Pressure Boundary
Pump casing (coolant)	Pressure Boundary
Pump casing (fuel oil)	Pressure Boundary
Pump casing (lube oil)	Pressure Boundary
Silencer	Pressure Boundary
Tank (coolant)	Pressure Boundary
Tank (fuel oil)	Pressure Boundary
Turbocharger (compressor)	Pressure Boundary

Table 2.3.3-38 Security

Component Type	Intended Function(s)
Turbocharger (turbine)	Pressure Boundary
Valve body	Pressure Boundary

The AMR results for these component types are indicated in Table 3.3.2-38, Auxiliary Systems - Security - Aging Management Evaluation.

Table 2.3.3-39 Buildings and Structures

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

The AMR results for these component types are indicated in Table 3.3.2-39, Auxiliary Systems - Buildings and Structures - Aging Management Evaluation.

Table 2.3.3-40 Containment Access

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Door actuator body (hydraulic drive)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (personnel hatch hand pump)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The AMR results for these component types are indicated in Table 3.3.2-40, Auxiliary Systems - Containment Access - Aging Management Evaluation.

Table 2.3.3-41 Electrical Power

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Heat exchanger (exciter air cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (exciter air cooler - tube)	Leakage Boundary (Spatial)

The AMR results for these component types are indicated in Table 3.3.2-41, Auxiliary Systems - Electrical Power - Aging Management Evaluation.

Table 2.3.3-42 Helium Vacuum Drying

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (dry shielded canister reflood pump)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The AMR results for these component types are indicated in Table 3.3.2-42, Auxiliary Systems - Helium Vacuum Drying - Aging Management Evaluation.

Table 2.3.3-43 Reactor Building Penetrations

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

The AMR results for these component types are indicated in Table 3.3.2-43, Auxiliary Systems - Reactor Building Penetrations - Aging Management Evaluation.

2.3.4 STEAM AND POWER CONVERSION SYSTEMS

2.3.4.1 Main Turbine

System Description

The main turbine system converts thermal energy into mechanical energy for the generator. The turbine is a conventional 1800 rpm, tandem-compound unit, consisting of one single-flow high-pressure cylinder and two double-flow low-pressure cylinders.

System Evaluation Boundary

The evaluation boundary for the main turbine system components subject to aging management review includes the high- and low-pressure turbine casings that retain steam in buildings containing safety-related components. The system does not contain any valves or piping components other than rupture discs.

System Intended Functions

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

UFSAR References

Additional details of the main turbine system can be found in the UFSAR, Section 10.3.3.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the main turbine system are listed below:

11448-SLRM-064A Sht 5

11448-SLRM-064A Sht 6

11548-SLRM-064A Sht 5

11548-SLRM-064A Sht 6

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-1, Main Turbine.

The aging management review results for these component types are indicated in Table 3.4.2-1, Steam and Power Conversion System - Main Turbine - Aging Management Evaluation.

2.3.4.2 Electro-Hydraulic Control

System Description

The electro-hydraulic control system controls the operation of the main turbine throttle, governor, reheat stop and intercept valves to control turbine speed, to control power output, and to trip the turbine when needed.

System Evaluation Boundary

The evaluation boundary for the electro-hydraulic control system components subject to aging management review includes the hydraulic fluid reservoirs, pumps, accumulators and piping components that contain hydraulic fluid in buildings containing safety-related components.

There are no passive mechanical components in the electro-hydraulic system whose integrity is relied upon to support safety-related functions or the turbine trip function.

System Intended Functions

Portions of the electro-hydraulic control system perform the following safety related functions: The system contains safety-related electrical relays. Therefore, the electro-hydraulic control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

Electrical portions of the electro-hydraulic control system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the electro-hydraulic control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the electro-hydraulic control system can be found in the UFSAR, Section 10.3.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the electro-hydraulic control system are listed below:

11448-SLRM-091B Sht 1

11448-SLRM-091B Sht 2

11548-SLRM-091B Sht 1

11548-SLRM-091B Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-2, Electro-Hydraulic Control.

The aging management review results for these component types are indicated in Table 3.4.2-2, Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation.

2.3.4.3 Lubricating Oil

System Description

The lubricating oil system supplies oil to the turbine-generator bearings and to the generator hydrogen seals. The system includes storage tanks and oil coolers, and has provisions to continuously recirculate oil from the oil reservoir through an oil purifier. The system also interfaces with the electro-hydraulic system via auto-stop oil to initiate turbine trips.

System Evaluation Boundary

The evaluation boundary for the lubricating oil system components subject to aging management review includes the lubricating oil reservoir and storage tanks, transfer and supply pumps, lubricating oil heat exchangers, filters, purifiers, and associated piping and components; the generator seal oil pumps, heat exchangers, filters and associated piping components; and the auto-stop oil piping and components. These components retain water or oil in buildings containing safety-related components. Vapor extractors and associated piping in the system do not contain fluid and are not subject to aging management review.

There are no passive mechanical components in the lubricating oil system whose integrity is relied upon to support the seal oil or turbine trip functions.

System Intended Functions

Portions of the lubricating oil system perform the following safety-related functions: The system includes safety-related electrical power to the seal oil backup pump. Therefore, the lubricating oil system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

Portions of the lubricating oil system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the lubricating oil system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the lubricating oil system can be found in the UFSAR, Section 8.5 and Section 10.3.7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the lubricating oil system are listed below:

11448-SLRM-076A Sht 1

11448-SLRM-076B Sht 1

11448-SLRM-091A Sht 1

11448-SLRM-091A Sht 2

11548-SLRM-076A Sht 1

11548-SLRM-076B Sht 1

11548-SLRM-091A Sht 1

11548-SLRM-091A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-3, Lubricating Oil.

The aging management review results for these component types are indicated in Table 3.4.2-3, Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation.

2.3.4.4 Main Steam

System Description

The main steam system transports steam produced in the steam generators to the main turbine for the production of electricity. Steam is conducted from each of the three steam generators through a steam flowmeter (venturi), a swing disk-type valve and an angle-type nonreturn valve into a common header outside the Containment. The steam passes from the header to the turbine stop-trip valves and then to the governor valves. Additionally, the system provides motive steam to the turbine-driven auxiliary feed pump, removes heat from the reactor coolant system via the code safety valves, steam generator power-operated relief valves, and/or condenser steam dump valves, and isolates steam flow to the main turbine following a reactor trip or during design basis events to prevent an excessive cooldown.

System Evaluation Boundary

The evaluation boundary for the main steam system components subject to aging management review includes the safety-related steam lines from the steam generators to the main steam isolation and non-return valves, main steam safety and pressure relief valves, and to the auxiliary feedwater pump turbine; the nonsafety-related steam lines from the non-return valves to the main turbine stop valves, condenser steam dump valves and moisture-separator reheater flow control valves (and attached piping to the first isolation valve), which are credited with providing isolation during fire and station blackout events if the main steam isolation valves fail to close; sensing lines for the turbine first stage pressure transmitters which feed the ATWS Mitigation System Actuation Circuitry; and the nonsafety-related steam dump, gland steam and associated attached piping components that provide support to directly connected safety-related components, or that retain water, steam or oil in buildings containing safety-related components.

System Intended Functions

Portions of the main steam system perform the following safety-related functions: The system removes heat from the reactor coolant system, provides overpressure protection for the reactor coolant and main steam systems, prevents uncontrolled blowdown of more than one steam generator, provides steam to the turbine driven auxiliary feedwater pump, provides containment isolation and provides safety-related indication. Therefore, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the main steam system contain 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 spatial interaction and structural integrity.

Portions of the main steam system 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, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the main steam system can be found in the UFSAR, Section 4.3.2, Section 10.3.1, Section 14.2.10.1, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-064A Sht 1

11448-SLRM-064A Sht 2

11448-SLRM-064A Sht 3

11448-SLRM-064A Sht 4

11448-SLRM-064A Sht 5

11448-SLRM-064A Sht 6

11448-SLRM-117A Sht 1

11548-SLRM-064A Sht 1

11548-SLRM-064A Sht 2

11548-SLRM-064A Sht 3

11548-SLRM-064A Sht 4

11548-SLRM-064A Sht 5

11548-SLRM-064A Sht 6

11548-SLRM-117A Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-4, Main Steam.

The aging management review results for these component types are indicated in Table 3.4.2-4, Steam and Power Conversion System - Main Steam - Aging Management Evaluation.

2.3.4.5 Heating

System Description

The heating system provides heating steam to various site buildings. It consists of a fuel oil supply that includes a fuel oil tank, pumps and associated piping components, two oil-fired auxiliary boilers, steam distribution piping to unit heaters and ventilation units in various buildings, steam traps, and condensate drain tanks and pumps. The system can also provide makeup fuel oil to the underground emergency generator storage tanks. The heating system corresponds to the portion of the auxiliary steam system described in the UFSAR that provides steam for area heating and steam to the CO_2 vaporizer.

System Evaluation Boundary

The evaluation boundary for the heating system components subject to aging management review includes 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. This includes fuel oil piping components in the fuel oil pump house and auxiliary boiler room, a condensate deaerator and associated components, boiler feed pumps, auxiliary boilers, steam supply piping component to various unit and ventilation heaters, a ventilation humidifier, steam traps and condensate drain piping, collection tanks and pumps.

There are no passive mechanical components in the heating system whose integrity is relied upon to support a safety-related function.

System Intended Functions

Portions of the heating system perform the following safety-related functions: The system contains safety-related electrical hand switches. Therefore, the heating system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the heating system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the heating 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.

UFSAR References

Additional details of the heating system can be found in the UFSAR, Section 10.3.2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRB-037A Sht 1

11448-SLRB-037B Sht 1

11448-SLRB-037B Sht 2

11448-SLRB-037B Sht 3

11448-SLRB-037B Sht 4

11448-SLRB-037C Sht 1

11448-SLRB-037D Sht 1

11448-SLRB-037E Sht 1

11448-SLRB-038A Sht 1

11448-SLRB-038A Sht 3

11548-SLRB-037A Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-5, Heating.

The aging management review results for these component types are indicated in Table 3.4.2-5, Steam and Power Conversion System - Heating - Aging Management Evaluation.

2.3.4.6 Extraction Steam

System Description

The extraction steam system provides steam to pre-heat the condensate in the feedwater heaters. During normal operation, the extraction steam system is the source of steam for the auxiliary steam system.

System Evaluation Boundary

The evaluation boundary for the extraction steam system components subject to aging management review includes the nonsafety-related extraction steam piping components from the turbine to the feedwater heaters, and the steam traps and associated piping components that retain water or steam in buildings containing safety-related components.

System Intended Functions

Portions of the extraction steam system contain 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 spatial interaction.

UFSAR References

Additional details of the extraction steam system can be found in the UFSAR, Section 10.3.2.2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-065A Sht 1

11448-SLRM-065A Sht 2

11448-SLRM-065A Sht 3

11548-SLRM-065A Sht 1

11548-SLRM-065A Sht 2

11548-SLRM-065A Sht 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-6, Extraction Steam.

The aging management review results for these component types are indicated in Table 3.4.2-6, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation.

2.3.4.7 Auxiliary Steam

System Description

The auxiliary steam system supplies low pressure, saturated steam to various plant systems.

Steam from the secondary system is reduced in pressure and supplied to the auxiliary steam system for space heating, process system heat exchangers, and process system air ejectors. Nearly all secondary steam used in the auxiliary steam system is condensed, returned to the condensate system, and then sent to either the condensate storage tank or the main condenser. A small quantity of secondary steam used in the auxiliary steam system for the after-condenser air ejectors and containment vacuum ejectors is not returned to the condensate system for reuse. Auxiliary steam used in the after-condenser air ejectors is condensed and drained to the storm sewage system or returned to the condenser. Auxiliary steam used in the containment vacuum ejectors is ejected to the atmosphere through the roof of the auxiliary building.

System Evaluation Boundary

The evaluation boundary for the auxiliary steam system components subject to aging management review includes system piping that is attached to, and supports integrity of the main steam system in the event the main steam trip valves cannot be shut during an Appendix R or station blackout event, up to and including the first isolation valves, as well as components that retain water or steam in buildings containing safety-related components.

System Intended Functions

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

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

UFSAR References

Additional details of the auxiliary steam system can be found in the UFSAR, Section 10.3.2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-066A Sht 1

11448-SLRM-066A Sht 2

11448-SLRM-066B Sht 1

11548-SLRM-066A Sht 1

11548-SLRM-066A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-7, Auxiliary Steam.

The aging management review results for these component types are indicated in Table 3.4.2-7, Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation.

2.3.4.8 Feedwater

System Description

The feedwater system is comprised of main feedwater and auxiliary feedwater subsystems. Main feedwater provides treated water to maintain inventory in the steam generators for the production of steam and to provide a heat sink for the reactor coolant system. Main feedwater components provide a flowpath for auxiliary feedwater flow to the steam generator and provide isolation of main feedwater flow in response to plant transients. Auxiliary feedwater provides an emergency source of water to the steam generators for reactor heat removal. Auxiliary feedwater provides a heat sink during design basis events including loss of power conditions. The system consists of three auxiliary feedwater pumps and associated components. In addition, both units' auxiliary feedwater pumps are cross-connected at the pump discharge so that either unit can supply auxiliary feedwater flow to the opposite unit if the opposite unit auxiliary feedwater pumps are unavailable. With one unit potentially supplying auxiliary feedwater to both units, the heat removal capacity of the emergency condensate storage tank, the normal source of auxiliary feedwater, is halved; therefore, a nonsafety-related emergency condensate makeup tank at each unit provides another reliable source of auxiliary feedwater.

System Evaluation Boundary

The evaluation boundary for the feedwater system components subject to aging management review includes the safety-related feedwater piping from outside Containment through the containment penetrations to the steam generators, the safety-related auxiliary feedwater pumps and associated suction and discharge piping components, and the nonsafety-related feedwater booster pumps and associated piping components from the emergency condensate makeup tanks (which are in the condensate system) to the auxiliary feedwater pump suctions, and the nonsafety-related main feedwater pumps, first-point feedwater heaters and piping components in buildings containing safety-related components. Additionally, nonsafety-related instrument air piping and valves provide structural support for the safety-related air accumulators and associated air supply piping components that provide closing air for the bypass feedwater regulating valves and are subject to aging management review. The main feedwater regulating valves have a similar safety-related air-to-close configuration, but the components that support that function have instrument air mark numbers and are evaluated within the instrument air system.

System Intended Functions

Portions of the feedwater system perform the following safety-related functions: The system provides water to the steam generators during and following design basis events, provides containment isolation, provides safety-related indication, and limits feedwater flow to a faulted steam generator. Therefore, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the feedwater system contain nonsafety-related components that provide a backup source of water to the suction of the auxiliary feedwater pumps, and portions contain 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 auxiliary feedwater delivery and for spatial interaction and structural integrity.

Portions of the feedwater system 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, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the feedwater system can be found in the UFSAR, Section 10.3.5, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRK-8M Sht 1

11448-SLRM-064A Sht 4

11448-SLRM-064B Sht 1

11448-SLRM-068A Sht 1

11448-SLRM-068A Sht 2

11448-SLRM-068A Sht 3

11448-SLRM-068A Sht 4

11448-SLRM-068B Sht 1

11548-SLRK-8G Sht 1

11548-SLRM-064A Sht 4

11548-SLRM-068A Sht 1

11548-SLRM-068A Sht 2

11548-SLRM-068A Sht 3

11548-SLRM-068A Sht 4

11548-SLRM-068B Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-8, Feedwater.

The aging management review results for these component types are indicated in Table 3.4.2-8, Steam and Power Conversion System - Feedwater - Aging Management Evaluation.

2.3.4.9 Condensate

System Description

The condensate system provides chemically treated water to the suction of the main feedwater pumps at sufficient pressure to support main feedwater pump operation.

The condensate system also provides the piping, valves, water storage, and makeup supply for auxiliary feedwater. An emergency condensate storage tank is provided for each unit. Each tank supplies water to the three auxiliary feedwater pumps through individual lines. In addition, both units' auxiliary feedwater pumps are cross-connected at the pump discharge so that either unit can supply auxiliary feedwater flow to the opposite unit if the opposite unit auxiliary feedwater pumps are unavailable. With one unit potentially supplying auxiliary feedwater to both units, the heat removal capacity of the emergency condensate storage tank, the normal source of auxiliary feedwater, is halved; therefore, a nonsafety-related emergency condensate makeup tank at each unit provides another reliable source of auxiliary feedwater.

System Evaluation Boundary

The evaluation boundary for the condensate system components subject to aging management review includes the safety-related emergency condensate storage tanks and the associated piping components to deliver water to the auxiliary feedwater pumps, the nonsafety-related emergency condensate makeup tanks that provide a backup auxiliary feedwater supply, the nonsafety-related main condenser hotwells, nonsafety-related piping that provides makeup to the component cooling system surge tanks, and nonsafety-related components that provide support to directly connected safety-related components, or that retain water in buildings containing safety-related components. These nonsafety-related components include the condensate pumps, second point through sixth point feedwater heaters, the heater drain coolers, and the piping components associated with flowpaths of condensate up to the suction of the main feedwater pumps. The condenser waterboxes, tubesheets and tubes are addressed in the circulating water system The foundations for the condensate storage tanks and the enclosures for the emergency condensate makeup tanks are addressed in the structural section of this application.

System Intended Functions

Portions of the condensate system perform the following safety-related functions: The system provides a safety-related source of water to the auxiliary feedwater pump suctions during design basis events, and the system provides safety-related indication. Therefore, the condensate system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the condensate system provide a nonsafety-related backup source of water to the auxiliary feedwater pump suctions, and other portions provide a pressure boundary for the component cooling and circulating water systems. Additionally, portions of the system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the condensate system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, and for spatial interaction and structural integrity.

Portions of the condensate system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) 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).

UFSAR References

Additional details of the condensate system can be found in the UFSAR, Section 10.3.5, Section 10.3.6, and Section Section 14B.5.1.7

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-067A Sht 1

11448-SLRM-067A Sht 2

11448-SLRM-067B Sht 1

11448-SLRM-067B Sht 2

11448-SLRM-067C Sht 1

11448-SLRM-067C Sht 2

11448-SLRM-068A Sht 3

11448-SLRM-068A Sht 4

11548-SLRM-067A Sht 1

11548-SLRM-067A Sht 2

11548-SLRM-067B Sht 1

11548-SLRM-067B Sht 2

11548-SLRM-067C Sht 1

11548-SLRM-067C Sht 2

11548-SLRM-068A Sht 3

11548-SLRM-068A Sht 4

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-9, Condensate.

The aging management review results for these component types are indicated in Table 3.4.2-9, Steam and Power Conversion System - Condensate - Aging Management Evaluation.

2.3.4.10 Condensate Polishing

System Description

The condensate polishing system removes dissolved salts and suspended solids from the condensate system. Each unit's condensate polishing system consists of an independent set of condensate demineralizers supplied from the main condensate header downstream of the condensate pumps. As condensate passes through the demineralizers, impurities are removed by interaction with the resin beads or by the filtration action of the overall resin bed. Each demineralizer discharge then passes through a resin trap, which prevents resin from entering the condensate stream, to an effluent header for return to the condensate system.

System Evaluation Boundary

The evaluation boundary for the condensate polishing system components subject to aging management review includes the piping components that retain water in buildings containing safety-related components.

System Intended Functions

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

UFSAR References

Additional details of the condensate polishing system can be found in the UFSAR, Section 10.3.5.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the condensate polishing system are listed below:

13058-SLRM-157B Sht 1

13058-SLRM-157E Sht 1

13058-SLRM-157L Sht 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-10, Condensate Polishing.

The aging management review results for these component types are indicated in Table 3.4.2-10, Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation.

2.3.4.11 Steam Drains

System Description

The steam drains system collects drains from the secondary plant and returns them to the feedwater or condensate system. Drains from the moisture separators, reheaters, and the number 1 and number 2 feedwater heaters are collected in the high-pressure heater drain tank and pumped into the suction of the feedwater pumps by one of two full-size high-pressure feedwater heater drain pumps. Drains from the low-pressure feedwater heaters are collected and routed to the condensate system.

System Evaluation Boundary

The evaluation boundary for the steam drains system components subject to aging management review includes the drains from the feedwater heaters and moisture separator reheaters, the associated heater drain tanks and pumps and flowpaths to the feedwater and condensate systems. These components are nonsafety-related components that retain water, steam or oil in buildings containing safety-related components. Some steam traps and associated piping components attached to the main steam system provide piping integrity are in support of the main steam system isolation function to preclude excessive cooldown during a fire or station blackout event.

There are no passive mechanical components in the steam drains system whose integrity is relied upon to support a safety-related function.

System Intended Functions

Portions of the steam drains system perform the following safety-related functions: The system contains safety-related electrical components that ensure availability of power supplies. Therefore, the steam drains system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

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

UFSAR References

Additional details of the steam drains system can be found in the UFSAR, Section 10.3.5.2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-066A Sht 1

11448-SLRM-069A Sht 1

11448-SLRM-069A Sht 2

11448-SLRM-069A Sht 3

11448-SLRM-069A Sht 4

11448-SLRM-070A Sht 1

11448-SLRM-070A Sht 2

11448-SLRM-070A Sht 3

11448-SLRM-070A Sht 4

11448-SLRM-078A Sht 1

11448-SLRM-078A Sht 2

11548-SLRM-066A Sht 1

11548-SLRM-069A Sht 1

11548-SLRM-069A Sht 2

11548-SLRM-069A Sht 3

11548-SLRM-069A Sht 4

11548-SLRM-070A Sht 1

11548-SLRM-078A Sht 1

11548-SLRM-078A Sht 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-11, Steam Drains.

The aging management review results for these component types are indicated in Table 3.4.2-11, Steam and Power Conversion System - Steam Drains - Aging Management Evaluation.

2.3.4.12 Blowdown

System Description

The blowdown system provides a flowpath for the continuous blowdown flow from the steam generator secondary-side to maintain acceptable steam generator water chemistry. The blowdown system isolates flow for containment isolation, to maintain steam generator inventory during transients, and in the event of a high energy line break.

System Evaluation Boundary

The evaluation boundary for the blowdown system components subject to aging management review includes the safety-related steam generator blowdown piping beginning within the steam generators, connecting to piping components in Containment, through containment penetrations to the outside containment isolation valves in the Auxiliary Building, as well as downstream nonsafety-related piping components that provide piping integrity for the circulating water system, or that provide support to directly connected safety-related components, or that retain water, including the blowdown heat exchangers and associated piping components in the Auxiliary Building and Turbine Building.

System Intended Functions

Portions of the blowdown system perform the following safety-related functions: The system isolates blowdown flow to mitigate design basis events, provides containment isolation, and provides safety-related instrumentation. Therefore, the blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the blowdown system contain nonsafety-related components that provide circulating water system integrity, and contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the blowdown system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, and for spatial interaction and structural integrity.

Portions of the blowdown system 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, the blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the blowdown system can be found in the UFSAR, Section 5.2.2, Section 7.2.3.2.7, Section 10.3.1.2, Section 14B.5.3.3, Table 5.2-1, Table 5.2-2, Table 7.5-1, and Table 7.5-2.

Subsequent License Renewal Boundary Drawings

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

11448-SLRM-124A Sht 1

11448-SLRM-124A Sht 2

11448-SLRM-124A Sht 3

11448-SLRM-124A Sht 4

11548-SLRM-124A Sht 1

11548-SLRM-124A Sht 2

11548-SLRM-124A Sht 3

11548-SLRM-124A Sht 4

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-12, Blowdown.

The aging management review results for these component types are indicated in Table 3.4.2-12, Steam and Power Conversion System - Blowdown - Aging Management Evaluation.

2.3.4.13 Steam Generator Recirculation and Transfer

System Description

The steam generator recirculation and transfer system is provided to protect the steam generator internals from corrosive attack during inactive periods by enabling the water chemistry to be controlled during such periods. The system is used in conjunction with nitrogen addition to ensure the exclusion of oxygen from the steam generator internals during wet layup conditions. Each steam generator has an independent external recirculation loop. The recirculation and transfer system pump takes suction from the steam generator upper shell and discharges to the steam generator through the blowdown pipe via a connection to the steam generator blowdown system. Each circulation loop has a cross connect to facilitate the transfer of a steam generator's contents to either of the other two steam generators, the liquid waste system, or the circulating water discharge.

System Evaluation Boundary

The evaluation boundary for the steam generator recirculation and transfer system components subject to aging management review includes the safety-related piping from the steam generators through containment penetrations to the containment isolation valves, and nonsafety-related pumps, heat exchangers and piping components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

Portions of the steam generator recirculation and transfer system perform the following safety-related functions: The system provides containment isolation and maintains pressure boundary integrity for the steam generators. Therefore, the steam generator recirculation and transfer system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the steam generator recirculation and transfer system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the steam generator recirculation and transfer 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.

UFSAR References

Additional details of the steam generator recirculation and transfer system can be found in the UFSAR, Section 10.3.1.2, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the steam generator recirculation and transfer system are listed below:

11448-SLRM-124A Sht 1

11448-SLRM-124A Sht 2

11448-SLRM-124A Sht 3

11548-SLRM-124A Sht 1

11548-SLRM-124A Sht 2

11548-SLRM-124A Sht 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-13, Steam Generator Recirculation and Transfer.

The aging management review results for these component types are indicated in Table 3.4.2-13, Steam and Power Conversion System - Steam Generator Recirculation and Transfer - Aging Management Evaluation.

Intentionally Blank

Screening Results Tables: Steam and Power Conversion Systems

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-1 Main Turbine

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Turbine casing	Leakage Boundary (Spatial)
Turbine casing (rupture disc)	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-1, Steam and Power Conversion System - Main Turbine - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-2 Electro-Hydraulic Control

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Flow indicator	Leakage Boundary (Spatial)
Heat exchanger (electro-hydraulic oil - channel)	Leakage Boundary (Spatial)
Heat exchanger (electro-hydraulic oil - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping	Leakage Boundary (Spatial)
Pump casing (electro-hydraulic control oil)	Leakage Boundary (Spatial)
Pump casing (transfer pump)	Leakage Boundary (Spatial)
Tank (electro-hydraulic oil reservoir)	Leakage Boundary (Spatial)
Tank (high pressure accumulator)	Leakage Boundary (Spatial)
Tank (low pressure accumulator)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-2, Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-3 Lubricating Oil

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow indicator	Leakage Boundary (Spatial)
Heat exchanger (generator seal oil - channel)	Leakage Boundary (Spatial)
Heat exchanger (generator seal oil - shell)	Leakage Boundary (Spatial)
Heat exchanger (lubricating oil - channel)	Leakage Boundary (Spatial)
Heat exchanger (lubricating oil - shell)	Leakage Boundary (Spatial)
Heater housing (lubricating oil conditioner)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (bearing lift)	Leakage Boundary (Spatial)
Pump casing (fill)	Leakage Boundary (Spatial)
Pump casing (oil conditioner)	Leakage Boundary (Spatial)
Pump casing (turbine lubricating oil)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (generator seal oil)	Leakage Boundary (Spatial)

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-3 Lubricating Oil

Component Type	Intended Function(s)
Tank (lubricating oil)	Leakage Boundary (Spatial)
Tank (oil conditioner drain and collection)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-3, Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-4 Main Steam

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flow restrictor (venturi)	Restricts Flow
Heat exchanger (moisture separator reheater - shell/channel)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Steam trap	Leakage Boundary (Spatial), Pressure Boundary
Strainer body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-4, Steam and Power Conversion System - Main Steam - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-5 Heating

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Heat exchanger (auxiliary boiler drum)	Leakage Boundary (Spatial)
Heat exchanger (converter shell)	Leakage Boundary (Spatial)
Heating coil (ventilation unit heater)	Leakage Boundary (Spatial)
Humidifier	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (auxiliary boiler feed)	Leakage Boundary (Spatial)
Pump casing (auxiliary boiler fuel oil)	Leakage Boundary (Spatial)
Pump casing (chemical injection)	Leakage Boundary (Spatial)
Pump casing (condensate)	Leakage Boundary (Spatial)
Pump casing (fuel oil transfer)	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 (blowdown)	Leakage Boundary (Spatial)
Tank (chemical mixing)	Leakage Boundary (Spatial)

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-5 Heating

Component Type	Intended Function(s)
Tank (condensate receiver)	Leakage Boundary (Spatial)
Tank (deaerator)	Leakage Boundary (Spatial)
Tank (drain)	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 3.4.2-5, Steam and Power Conversion System - Heating - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-6 Extraction Steam

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Expansion joint	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Steam trap	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-6, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-7 Auxiliary Steam

Component Type	Intended Function(s)
Air ejector	Leakage Boundary (Spatial)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (drain receiver)	Leakage Boundary (Spatial)
Steam trap	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (drain receiver)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-7, Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-8 Feedwater

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Pressure Boundary
Flexible hose	Leakage Boundary (Spatial)
Flow element	Pressure Boundary, Restricts Flow
Flow restrictor (venturi)	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Heat exchanger (first point feedwater heater - channel)	Leakage Boundary (Spatial)
Heat exchanger (first point feedwater heater - shell)	Leakage Boundary (Spatial)
Heat exchanger (main feedwater pump stuffing box jacket)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (auxiliary feedwater booster)	Pressure Boundary
Pump casing (auxiliary feedwater lubricating oil)	Pressure Boundary
Pump casing (auxiliary feedwater)	Pressure Boundary
Pump casing (main feedwater lubricating oil)	Leakage Boundary (Spatial)
Pump casing (main feedwater)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-8 Feedwater

Component Type	Intended Function(s)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Strainer element	Filtration
Tank (auxiliary feedwater pump lubricating oil)	Pressure Boundary
Tank (main feedwater pump lubricating oil)	Leakage Boundary (Spatial)
Turbine casing	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 3.4.2-8, Steam and Power Conversion System - Feedwater - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-9 Condensate

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Condenser (hotwell)	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Heat exchanger (drain cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (drain cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (feedwater heater - channel)	Leakage Boundary (Spatial)
Heat exchanger (feedwater heater - shell)	Leakage Boundary (Spatial)
Heat exchanger (gland steam condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (gland steam condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (pump motor oil - cooling coil)	Leakage Boundary (Spatial)
Heat exchanger (pump stuffing box - jacket)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (condensate)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-9 Condensate

Component Type	Intended Function(s)
Tank (emergency condensate makeup)	Pressure Boundary
Tank (emergency condensate storage)	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 3.4.2-9, Steam and Power Conversion System - Condensate - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-10 Condensate Polishing

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 3.4.2-10, Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-11 Steam Drains

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (heater drain pump motor oil cooling coil)	Leakage Boundary (Spatial)
Heat exchanger (heater drain pump stuffing box jacket)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (gland steam condensate)	Leakage Boundary (Spatial)
Pump casing (heater drains)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Steam trap	Leakage Boundary (Spatial), Pressure Boundary
Strainer body	Leakage Boundary (Spatial)
Tank (gland steam condenser receiver)	Leakage Boundary (Spatial)
Tank (heater drain receiver, moisture separator drain pot)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

See Table 2.1.5-1 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 - Steam Drains - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-12 Blowdown

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (blowdown - channel)	Leakage Boundary (Spatial)
Heat exchanger (blowdown - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
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 3.4.2-12, Steam and Power Conversion System - Blowdown - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.3.4-13 Steam Generator Recirculation and Transfer

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (steam generator recirculation channel)	Leakage Boundary (Spatial)
Heat exchanger (steam generator recirculation shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (steam generator recirculation and transfer)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-13, Steam and Power Conversion System - Steam Generator Recirculation and Transfer - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Intentionally Blank

See Table 2.1.5-1 for definitions of intended functions.

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

2.4.1 CONTAINMENTS, STRUCTURES, AND COMPONENT SUPPORTS

2.4.1.1 Containment

System Description

The Unit 1 and Unit 2 Containments are Seismic Class I structures that house the reactor vessel and other nuclear steam supply system components for the respective unit. Each Containment consists of a reinforced concrete cylinder with a hemispherical dome and a flat, 10-foot-thick reinforced concrete mat foundation. Directly below the mat is a 4-inch-thick layer of porous concrete that serves as a horizontal drain under the entire structure. A waterproof membrane is located below the porous concrete and extends up the containment wall to ground level. The foundation is supported on highly consolidated Miocene clays.

Attached to the inside of the cylindrical containment wall and dome is a liner of varying thickness. The liner attachments to the cylindrical wall and dome are Nelson concrete anchors that were cast in the containment concrete as the concrete was poured against the liner. Steel insert plates are used in the containment liner such that support loads are transmitted to the concrete Containment. The Containment does not require participation of the liner as a structural component.

Leak tightness testing of liner welds during construction was performed by welding a structural steel test channel over each weld. The test channels of the dome of the Containment are located outside the liner plate, with test holes tapped and plugged from the inside. Test channels of the floor liner are piped through the concrete, which covers the floor, to test port panels, and are plugged. Test channels on the straight side walls of the Containment are located inside the liner plate, and are tapped and plugged from the inside. The test channel welds are tested as an integral part of the containment liner plate welds during the operational phase leak rate testing. The test channels are capable of withstanding all loads that might be imposed on them during normal, test, and design basis accident conditions without any loss of function, and the presence of the test channels does not in any way impair the performance of the containment liner itself.

The bottom of the containment liner is covered with a thick reinforced concrete slab for protection. The Containment is divided by the crane wall that supports the polar crane into an outer annulus section and a central section. The central section is further subdivided into equipment cubicles that are connected to each other and to the outer annulus by open archways, grating floors, and unsealed penetrations. A Seismic Class I drainage sump with a stainless steel liner is provided in the containment basement.

The Containment contains personnel and equipment access openings. The personnel access hatch opening has an inner and an outer door that are maintained in the closed position by interlocking tooth closure mechanisms. The equipment access hatch is a large diameter single-door equipment hatch that is bolted in-place to the interior of the exterior containment wall. A two-door emergency escape air lock is provided through the equipment hatch for emergency access to the Containment. The emergency escape air lock inner door has steel strong backs that secure the door closed. There are no strong backs for the outer door of the emergency escape air lock.

The equipment hatch platform, which is located adjacent to the equipment access hatch of each Containment, supports the missile barrier located in front of the equipment access hatch.

A Seismic Class I reinforced concrete reactor cavity with a butt-welded stainless steel liner is provided in the Containment for refueling. The normally dry reactor cavity forms a pool above the reactor when it is filled with borated water for refueling. The reactor vessel flange is sealed to the bottom of the reactor cavity by the reactor cavity seal ring that prevents leakage of refueling water from the cavity.

The Containment has numerous mechanical and electrical penetrations that form part of the containment pressure boundary, all of which are within the scope of subsequent license renewal. The penetrations are welded to the containment liner and provide a seal between Containment and the outside atmosphere. High temperature piping penetrations include inner and outer coolers to limit the heat transferred to the containment concrete wall. The high temperature penetrations are cooled by the component cooling system.

A fuel transfer tube penetration is provided in the Containment to permit fuel movement between the refueling canal in the Containment and the spent fuel pool in the Fuel Building. The fuel transfer tube assembly, capped with a blind flange, also forms part of the containment pressure boundary. The fuel transfer tube assembly and blind flange are evaluated with the fuel handling system. A protection shield encloses the fuel transfer tube at the Containment and Fuel Building interface. The fuel transfer tube enclosure protection shield is evaluated with the Containment.

In addition, a dome opening for ventilation during construction is installed at the apex of the Containment. The ventilation dome opening is sealed by a welded plug on the liner side and has a hatch cover located on the outside of the Containment, and is filled with sandbags.

The reactor vessel head replacement project created and restored a construction opening in the Containment in accordance with administrative procedures and the design control program. The opening was used to facilitate the movement of original and replacement reactor vessel heads in and out of the Containment. The opening was restored to meet the original design bases of the Containment.

Service Level I coatings are used in areas inside the Containment (e.g., steel liner, penetrations, and concrete walls and floors), where the coating failure could adversely affect the operation of post-accident fluid systems by clogging the emergency core cooling systems suction strainers and thereby impair safe shutdown.

System Evaluation Boundary

The evaluation boundary for the containment structural members subject to aging management review includes structural members of the Containment, including basemat, drainage sump, internal structural members, waterproof membrane, and penetrations (personnel and emergency airlocks and equipment hatch, piping penetrations, electrical penetrations, ventilation dome opening with hatch cover, and heating and ventilation penetration). The refueling pool liner, reactor cavity liner, fuel transfer tube enclosure protection shield, and the reactor cavity seal ring are also included in the containment evaluation boundary.

For mechanical penetrations, flued heads and isolation valves are evaluated with the 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 containment evaluation boundary. The fuel transfer tube assembly and blind flange are evaluated for aging management with the fuel handling system. Fuel transfer tube supports are evaluated for aging management with the Component Supports. The sump screen assembly installed to prevent debris from entering the containment sump is evaluated for aging management with the recirculation spray system.

The gaskets and seals identified as O-rings of the equipment hatch and personnel hatch doors provide leak-tight conditions inside Containment.

System Intended Functions

Portions of the Containment perform the following safety-related functions: The Containment 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 Containment is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Containment provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Containment is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Containment 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, the Containment is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Containment can be found in the UFSAR, Section 5.1, Section 15.5.1, Section 15.5.2, Table 5.2-1, and Table 5.2-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Containment is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-1, Containment

The aging management review results for these component types are indicated in Table 3.5.2-1, Containments, Structures and Component Supports - Containment - Aging Management Evaluation.

2.4.1.2 Auxiliary Building Structure

System Description

The Auxiliary Building Structure, which is common to both units, includes the cable vaults (also called containment penetration vaults), and pipe tunnel structures. For each unit, the pipe tunnel structure is the pipe tunnel from the Containment to the Auxiliary Building and is located below the cable vault. The cable vault includes the cable tunnel and motor control center room.

The following structures are included:

- Auxiliary Building

- Cable vaults (also called containment penetration vaults)*

- Pipe tunnels

- Cable tunnels*

- Upper cable vault motor control center rooms for both units

*These items are separate from the Auxiliary Building, but accessed via the Auxiliary Building, and are therefore included as a part of the Auxiliary Building Structure for the purposes of subsequent license renewal.

The above structures are on a common foundation. The term Auxiliary Building Structure should be understood to include the Auxiliary Building and each unit's cable vault, pipe tunnel, cable tunnel, and motor control center room, unless specified otherwise.

The Auxiliary Building Structure is a four-story structure located between the Unit 1 and Unit 2 Containments. It contains systems that service both units. The structure has a reinforced concrete foundation mat. The lower two stories are below grade (substructure). Substructure walls are constructed of reinforced concrete or masonry blocks. The third and fourth stories are enclosed with metal siding and metal roof decking, which are supported by structural steel. Intermediate concrete floor slabs are cast on metal deck forms, which remain in place, or they are cast on removable form work supported by scaffolding.

The roof over a portion of the Auxiliary Building Structure is a built-up roofing system, which is comprised of steel decking covered by a single-ply, mechanically attached membrane. Reinforced concrete walls and slabs are provided for enclosing components such as volume control tanks and charging pumps. The personnel hatch of the Containment is enclosed with concrete walls for biological and missile shielding. The upper stories of the Auxiliary Building Structure are enclosed with metal siding.

Pre-cast concrete hatch covers are provided over the ion exchange cubicles and in other locations in the ground floor for handling equipment. Many of the slabs and walls are constructed of barytes (barium compound) concrete for additional radiation shielding. Concrete slabs and walls constructed of barytes are evaluated as concrete elements.

Rolling steel and hollow metal doors are provided for access. The roof is comprised of steel framing covered with steel decking and a single-ply, mechanically attached membrane.

The cable vault, cable tunnel, motor control center room, and pipe tunnel structures comprise a reinforced concrete structure with three exterior walls and a fourth side open to the exterior southeast quadrant of the Unit 1 containment shell and the southwest quadrant of the Unit 2 containment shell. This structure consists of the pipe tunnel in the first story, the cable vault and cable tunnel in the second story, and the motor control center and containment penetration purge lines and valve in the third story. The pipe tunnel provides access for piping running between the Containments and the Auxiliary Building Structure. The cable tunnel provides access for the cable tray running between the Containments and the Service Building.

System Evaluation Boundary

The evaluation boundary for the Auxiliary Building Structure includes the foundation, internal structural members, external walls, roof, piping penetrations, electrical penetrations, and heating and ventilation penetrations.

System Intended Functions

Portions of the Auxiliary Building Structure perform the following safety-related functions: The Auxiliary Building Structure provides structural support, and shelter and protection for safety-related SSCs required to mitigate the consequences of accidents that could result in potential offsite exposure. Therefore, the Auxiliary Building Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Auxiliary Building Structure provide structural support, and shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Auxiliary Building Structure is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Auxiliary Building Structure 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, the Auxiliary Building Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Auxiliary Building Structure can be found in the UFSAR, Section 9.10.4.3, Section 9.10.4.7 through Section 9.10.4.11, and Section 15.6.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Auxiliary Building Structure is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-2, Auxiliary Building Structure.

The aging management review results for these component types are indicated in Table 3.5.2-2, Containments, Structures and Component Supports - Auxiliary Building Structure - Aging Management Evaluation.

2.4.1.3 Discharge Canal

System Description

The Discharge Canal conveys water flow from the discharge tunnel seal pits to the James River. The canal is excavated in earth and is designed to carry the flow of the two units with a velocity of about 2.2 feet per second at mean low water.

The Discharge Canal ranges in width from 20 feet at its head to 65 feet at its terminus and has an overall length of 2900 feet. The section of the canal that extends from the power station to the river shoreline is lined with a concrete liner. The last 1200 feet of the Discharge Canal extends into the James River.

System Evaluation Boundary

The evaluation boundary of the Discharge Canal structural members subject to aging management review begins at the discharge structure's seal pits and ends at the beginning of rock groins that extend into the river. The structural members subject to aging management review includes the earthen dike and embankment and the concrete liner.

System Intended Functions

Portions of the Discharge Canal provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Discharge Canal is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Discharge Canal are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Discharge Canal is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Discharge Canal can be found in the UFSAR, Section 10.3.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Discharge Canal is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-3, Discharge Canal.

The aging management review results for these component types are indicated in Table 3.5.2-3, Containments, Structures and Component Supports - Discharge Canal - Aging Management Evaluation.

2.4.1.4 Intake Canal

System Description

The Intake Canal is an earthen structure located between the Low-Level Intake Structure at the James River and the High-Level Intake Structure at the station. The canal is part of the flowpaths for both the circulating water system and the service water system and acts as a reservoir for these systems. The Intake Canal is about 1.7 miles long and is lined with reinforced concrete. The James River and the safety-related Intake Canal provide a source of cooling water for plant shutdown, and they form the ultimate heat sink for SPS.

The Intake Canal is excavated in soil, and a portion of the excavated soil was used to construct an embankment along each side to form the canal. The bottom and inside slopes of the canal are lined with reinforced concrete. At three separate locations, storm sewer lines consisting of one 30-inch and two 36-inch reinforced concrete pipes are installed underneath and transverse to the canal.

System Evaluation Boundary

The evaluation boundary of the Intake Canal structural members subject to aging management review begins at the Low-Level Intake Structure and ends at the High-Level Intake Structures. The structural members subject to aging management review include the earthen dike and embankment, the concrete liner, and the concrete encasing the service water lines for missile protection.

The safety-related emergency service water lines encased in reinforced concrete are evaluated for aging management in open water systems. The reinforced concrete missile barrier that provides protection to the emergency service water lines is in the scope of subsequent license renewal and evaluated with Earthen Structures.

System Intended Functions

Portions of the Intake Canal perform the following safety-related functions: The Intake Canal provides structural support, shelter and protection for safety-related SSCs required to provide the capability to shutdown the reactor and maintain it in a safe shutdown condition. Therefore, the Intake Canal is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

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

UFSAR References

Additional details of the Intake Canal can be found in the UFSAR, Section 2.1.4.3, Section 2.1.5.1.4, Section 2.4.9, Section 9.9, Section 10.3.4, and Section 15.6.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Intake Canal is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-4, Intake Canal.

The aging management review results for these component types are indicated in Table 3.5.2-4, Containments, Structures and Component Supports - Intake Canal - Aging Management Evaluation.

2.4.1.5 Fuel Building

System Description

The Fuel Building Structure is a common facility for both Unit 1 and Unit 2. The Fuel Building Structure includes the Fuel Building, the new fuel storage area, the spent fuel pool (including transfer canals), and the spent fuel storage racks.

Fuel Building

The Fuel Building is supported by a reinforced concrete mat, which is founded on concrete-filled steel pipe piles. The enclosing exterior walls extend from the top of the mat. The concrete beams and walls support the reinforced-concrete intermediate floor slabs. Concrete and masonry walls inside the Fuel Building provide shielding and support for the mechanical and electrical components and commodities.

The upper portion of the Fuel Building is enclosed with metal siding on a structural steel frame, extending from the top of the concrete walls to the roof. Metal siding is used on the east and south faces of the building. The roof is covered with metal decking and a single-ply, mechanically attached membrane roofing system. The superstructure walls and the roof, as well as the platforms, walkways, and stairs, are supported on structural steel framing. Steel hatch covers are provided on the roof for removing the fuel pit coolers, if necessary.

The Fuel Building Structure’s reinforced-concrete structure and steel superstructure are Seismic Class I. Exterior concrete walls are designed to withstand tornado-generated missiles.

In the northeast portion of the Fuel Building is the north bay crane enclosure, also known as the Decontamination Building, which is a structural steel frame building with metal siding and roof.

Just north of the Fuel Building are the Boron Recovery Pump House, also known as the Primary Grade Water Pump House, and the Health Physics (HP) Yard Office Building. The exterior and interior walls for the Boron Recovery Pump House and HP Yard Office Building are constructed of reinforced concrete and masonry blocks. The roof for these buildings consists of metal decking covered with built-up roofing.

New Fuel Storage Area

Structural steel framing members are attached to the Fuel Building Structure's concrete floor to provide support for the new fuel storage assembly's stainless steel guide tubes.

Spent Fuel Pool and Transfer Canals

The spent fuel pool and transfer canals are reinforced concrete structures, lined inside with stainless steel plates. The liner plate is anchored to the concrete side with steel anchors, stiffeners, and other appurtenances. The liner plate is not a load-bearing structural component. The spent fuel pool liner includes a leak chase system with embedded tell-tale piping that provides a leak collection mechanism for all of the liner seal welds. The transfer canal gate, spent fuel storage racks and cask pads are also fabricated from stainless steel.

The spent fuel pool receives spent fuel from the Containment through fuel transfer tubes, which enter canals on the east and west ends of the Fuel Building Structure. Each of the transfer tubes is located within a tube enclosure (including expansion joints), that is welded to embedded steel. The spent fuel pool and transfer canals are Seismic Class 1 structures. All equipment located inside the spent fuel pool is constructed of stainless steel for corrosion resistance.

Spent Fuel Storage Racks

The spent fuel storage racks are high-density racks, which are fabricated from stainless steel material, all submerged in the spent fuel pool. The freestanding racks, which are laterally restrained at the floor, are resting on the floor support pads, which are integrally connected to embedded plates. The spent fuel storage racks are designed as Seismic Class I structures.

System Evaluation Boundary

The evaluation boundary for the Fuel Building includes the foundation mat, concrete-filled steel pipe piles, pipe tunnel, piping penetrations, electrical penetrations, and heating and ventilation penetrations. The internal structural members, external walls, and roof, constructed of reinforced concrete, steel framing, metal siding and roofing membrane, are within the evaluation boundary.

Attached to the northeast portion of the Fuel Building is the north bay crane enclosure, also known as the Decontamination Building, which is a structural steel frame building with metal siding and roof. This structure is within the evaluation boundary of the Fuel Building.

The evaluation boundary for the Fuel Building includes the reinforced concrete and masonry block walls (exterior and interior), steel decking, and built-up roofing for the Boron Recovery Pump House. The evaluation boundary for the Fuel Building includes the reinforced concrete and masonry block walls (exterior), steel decking, and built-up roofing for the HP Yard Office Building. The HP Yard Office Building is within the scope of subsequent license renewal due to potential spatial interaction with the adjacent Fuel Building (Criterion of 10 CFR 54.4(a)(2)); therefore, the interior building walls for the building are not included in the evaluation boundary.

The evaluation boundary for the new fuel storage area includes structural steel framing members attached to the concrete floor.

The evaluation boundary for the spent fuel pool and transfer canals includes the reinforced concrete structures, stainless steel liners, transfer canal gates, spent fuel storage racks, and cask pads.

The fuel transfer tubes and bellows expansion joints are evaluated with the fuel handling system.

System Intended Functions

Portions of the Fuel Building Structure perform the following safety-related functions: The Fuel Building 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 Building Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Fuel Building Structure provide structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Fuel Building Structure is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Fuel Building Structure are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Fuel Building Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Fuel Building Structure can be found in the UFSAR, Section 2.4, Section 9.12, Section 15.2, Section 15.4, Section 15.6, Section 15.7, Appendix 9A, and Appendix 9B.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Fuel Building Structure is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-5, Fuel Building Structure.

The aging management review results for these component types are indicated in Table 3.5.2-5, Containments, Structures and Component Supports - Fuel Building Structure - Aging Management Evaluation.

2.4.1.6 Discharge Tunnel and Seal Pit

System Description

Outlet water from the condenser is directed to a single concrete discharge tunnel via four concrete encased steel pipes. A separate discharge tunnel that provides a gravity flow to the discharge canal is provided for each unit.

The discharge tunnel is a below grade reinforced concrete structure that is soil supported. The discharge tunnel widens in the area of the seal pit, which is located at the edge of the discharge canal. The seal pit has a reinforced concrete wall (weir) across the mouth of the discharge tunnel, which forms a dead end, forcing the flow up and over the wall into the discharge canal, where the water is returned to the main body of the river.

System Evaluation Boundary

The evaluation boundary of the Discharge Tunnel and Seal Pit structural members subject to aging management review includes the reinforced concrete components from the tie-in of the steel pipes to the discharge canal.

The steel circulating water pipes encased in concrete and the reinforced concrete pipes are within the scope of subsequent license renewal but are addressed in the circulating water system.

System Intended Functions

Portions of the Discharge Tunnel and Seal pit provide structural support, and shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Discharge Tunnel and Seal pit are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Discharge Tunnel and Seal Pit are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Discharge Tunnel and Seal Pit are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Discharge Tunnel and Seal Pit can be found in the UFSAR, Section 10.3.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Discharge Tunnel and Seal Pit is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-6, Discharge Tunnel and Seal Pit.

The aging management review results for these component types are indicated in Table 3.5.2-6, Containments, Structures and Component Supports - Discharge Tunnel and Seal Pit - Aging Management Evaluation.

2.4.1.7 High Level Intake Structure

System Description

The safety-related High Level Intake Structure, located at the station end of the intake canal, is a four-bay reinforced concrete structure and is soil-supported on a reinforced concrete mat foundation. An identical High Level Intake Structure is provided for each unit.

The High Level Intake Structure directs the intake canal water through and into 96-inch (diameter) pipes that provide a gravity flow path to each main condenser and service water system. Trash racks and traveling water screens are provided at the mouth of each bay to remove debris from the incoming water. Portable metal seal plates are provided to permit de-watering of the structure or to isolate Turbine Building flooding. Turbine Building flooding, which could occur as a result of a rupture in the circulating water system or service water system upstream of the first canal isolation valve, can be isolated by installing seal plates at the High Level Intake Structure. Rubber gaskets are used to ensure that the seal plates remain watertight. The seal plates are stored in racks adjacent to the High Level Intake Structure. Stairs and a platform provide access to the deck of the structure.

A High Level Control House is located on the deck of the High Level Intake Structure. The High Level Control House is a masonry block structure that houses nonsafety-related switchgear required to operate the equipment at the High Level Intake Structure. Missile shield enclosures are also installed on the deck of the High Level Intake Structure that provide protection for the instrument cable to the intake canal level probes. Concrete missile barriers provide protection for the service water lines.

System Evaluation Boundary

The evaluation boundary of the High Level Intake Structure includes the foundation, internal structural members, external walls, missile barriers, and roof. The High Level Control House is within the evaluation boundary due to its location on top of the safety-related High Level Intake Structure where its failure could potentially impact safety-related functions. All four Unit 1 High Level Intake Structure trash racks and two Unit 2 High Level Intake Structure trash racks associated with the service water system are included in the evaluation boundary. Also included in the boundary are the seal plates and the access stairs and platform. The evaluation boundary ends at the 96-inch (diameter) concrete pipes that provide a gravity flow path to each main condenser and service water system. These 96-inch pipes are evaluated for aging management with the circulating water system.

The traveling water screens are active components and do not require aging management.

The instrument cable and the intake canal level probes are evaluated for aging management as electrical components.

System Intended Functions

Portions of the High Level Intake Structure perform the following safety-related functions: The High Level Intake Structure provides structural support, shelter and protection, and flow path for safety-related SSCs required to provide the capability to shutdown the reactor and maintain it in a safe shutdown condition. Therefore, the High Level Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the High Level Intake Structure provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the High Level Intake Structure is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the High Level Intake Structure are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the High Level Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the High Level Intake Structure can be found in the UFSAR, Section 9.10.4.16, Section 10.3.4, and Appendix 9C.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the High Level Intake Structure is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-7, High Level Intake Structure.

The aging management review results for these component types are indicated in Table 3.5.2-7, Containments, Structures and Component Supports - High Level Intake Structure - Aging Management Evaluation.

2.4.1.8 Low Level Intake Structure

System Description

The safety-related Low Level Intake Structure, located on the shore end of the James River intake channel, is an eight-bay reinforced concrete structure, and is soil-supported on a reinforced concrete mat foundation. Each bay is separated by reinforced concrete wall and houses one of the eight circulating water pumps. Additionally, three of the eight bays have an emergency diesel driven service water pump. Before entering the pumps, river water passes through trash racks and traveling screens at the mouth of each bay. Portable floating bulkheads (stop logs) are provided to permit dewatering of the individual bays. An Emergency Service Water Pump House and a Low Level Control House (Switchgear Building) are located on top of the Low Level Intake Structure.

The safety-related Emergency Service Water Pump House is a reinforced concrete structure that provides support, shelter and protection for the emergency diesel driven service water pumps, associated diesel drives, switchgear, and a diesel fuel-oil storage tank. The structure is divided into two rooms (i.e., service water pump area and diesel fuel-oil storage area) by a combination concrete and masonry block (fire barrier) wall and a fire barrier door. The concrete wall provides support for the masonry block wall and serves as a flood barrier for leakage from the diesel fuel-oil tank. Two steel access platforms and stairs are provided for entrance to the service water pump room. Metal sliding doors are provided for missile protection. Whenever hurricane conditions are forecasted or exist, removable flood barriers (portable gates) are installed at the entrance to the service water pump room and at the end of the diesel fuel-oil storage room. Rubber gaskets are used to ensure that the portable gates remain watertight.

The Emergency Service Water Pump House ventilation consists of wall and roof mounted air louvers. The roof mounted air louvers are protected by a concrete missile shield. The wall louvers are protected by steel missile shields. The wall air intake louver openings are also protected against flooding by watertight wells installed on the interior wall. The exhaust piping for the emergency diesel-driven service water pumps is vented on the roof and includes missile protection.

The Low Level Control House (Switchgear Building) is a concrete and masonry block structure that contains the electrical equipment required to operate the nonsafety-related circulating water equipment.

System Evaluation Boundary

The evaluation boundary of the Low Level Intake Structure includes the foundation, internal structural members, external walls, roof, ventilation penetrations, three trash racks associated with the service water system, and the attached Emergency Service Water Pump House structure and access platforms. The Low Level Control House (Switchgear Building) is within the evaluation boundary due to its location on top of the safety-related Low Level Intake Structure where its failure could potentially impact safety-related functions.

Structures and components evaluated for the Low Level Intake Structure and determined not in the scope of subsequent license renewal are the five trash racks associated with the circulating water system, trash rack rake, the portable floating bulkheads (stop logs). These structures and components do not perform a license renewal intended function and their failure will not prevent the satisfactory accomplishment of a safety-related function.

The traveling screens are active components and do not require aging management.

System Intended Functions

Portions of the Low Level Intake Structure perform the following safety-related functions: The Low Level Intake Structure provides structural support, shelter and protection, and flow path for safety-related SSCs required to provide the capability to shutdown the reactor and maintain it in a safe shutdown condition. Therefore, the Low Level Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Low Level Intake Structure provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Low Level Intake Structure is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Low Level Intake Structure are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Low Level Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Low Level Intake Structure can be found in the UFSAR, Section 10.3.4 and Section 2.3.1.2.2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Low Level Intake Structure.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-8, Low Level Intake Structure.

The aging management review results for these component types are indicated in Table 3.5.2-8, Containments, Structures and Component Supports - Low Level Intake Structure - Aging Management Evaluation.

2.4.1.9 Black Battery Building

System Description

The Black Battery Building is a pre-engineered one-story building that consists of a steel structure with metal roof panels and metal siding panels. The building structure is founded on a reinforced concrete grade slab in the south yard between the condensate storage tanks and the Unit 1 station service transformers. The building does not abut any other structure.

The Black Battery Building is a nonsafety-related, non-seismic structure that houses batteries and associated power supply accessories for the anticipated transients without scram mitigation system's actuation circuitry panel located in the Service Building, as well as miscellaneous auxiliaries not within the scope of subsequent license renewal.

System Evaluation Boundary

The evaluation boundary for the Black Battery Building includes structural bolting, concrete elements associated with the foundation, curbs, and pads and steel elements associated with beams, columns, baseplates, bracing, doors, wall panels and roofing.

System Intended Functions

Portions of the Black Battery Building are relied upon for compliance with regulations for Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the Black Battery Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Black Battery Building can be found in the UFSAR, Section 8.4.4 and Figure 8.4-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Black Battery Building is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-9, Black Battery Building.

The aging management review results for these component types are indicated in Table 3.5.2-9, Containments, Structures and Component Supports - Black Battery Building - Aging Management Evaluation.

2.4.1.10 Central Alarm Station

System Description

The Central Alarm Station is a modular steel structure. The building structure is founded on a reinforced concrete grade slab south of the Unit 1 emergency condensate storage tank. The building does not abut any other structure.

The Central Alarm Station is a nonsafety-related, non-seismic structure that houses a security diesel generator and associated electrical distribution components that supply power to emergency lighting used during responses to fires, and that also supply power to security equipment not within the scope of subsequent license renewal.

System Evaluation Boundary

The evaluation boundary for the Central Alarm Station includes structural bolting, concrete elements associated with the foundation, walls, curbs, and pads, steel elements associated with beams, columns, baseplates, bracing, doors, wall panels, and roofing and components of the roofing membrane.

System Intended Functions

Portions of the Central Alarm Station are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Central Alarm Station is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Central Alarm Station is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-10, Central Alarm Station.

The aging management review results for these component types are indicated in Table 3.5.2-10, Containments, Structures and Component Supports - Central Alarm Station - Aging Management Evaluation.

2.4.1.11 Condensate Polishing Building

System Description

The Condensate Polishing Building is a two-story structure that is enclosed with metal siding above grade. The roof consists of metal decking covered with built-up roofing. The Condensate Polishing Building's steel structure is founded on a reinforced concrete mat. The concrete floors and steel framings are located at various elevations.

The Condensate Polishing Building is a nonsafety-related, non-seismic structure. No safety-related equipment or nonsafety-related equipment with the potential to affect safety-related equipment is located in the Condensate Polishing Building. The building houses fire suppression equipment credited for fire protection and electrical components that support response to a station blackout.

System Evaluation Boundary

The evaluation boundary for the Condensate Polishing Building includes structural bolting, concrete elements associated with the foundation, floor slabs, curbs, and pads, concrete block associated with the elevator shaft and fire barrier walls (fire barriers not credited for 10 CFR 50.48), steel elements associated with beams, columns, baseplates, bracing, doors, wall panels, stairways, ladders, railings, and roofing, and roofing membrane elements associated with the built-up roofing.

System Intended Functions

Structural integrity of the Condensate Polishing Building prevents collapse into adjacent structures containing safety-related components. Therefore, the Condensate Polishing Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2).

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

UFSAR References

Additional details of the Condensate Polishing Building can be found in the UFSAR, Section 9.10.4.28.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Condensate Polishing Building is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-11, Condensate Polishing Building.

The aging management review results for these component types are indicated in Table 3.5.2-11, Containments, Structures and Component Supports - Condensate Polishing Building - Aging Management Evaluation.

2.4.1.12 Laundry Facility

System Description

The Laundry Facility consists of a single-story reinforced concrete masonry structure with a built-up roof over precast concrete slabs supported by structural steel. The foundation is a reinforced concrete slab-on-grade.

The Laundry Facility is a nonsafety-related structure that is located east of the Unit 2 Containment. No safety-related equipment or nonsafety-related equipment with the potential to affect safety-related equipment is located in the Laundry Facility. The building houses fire suppression equipment credited for fire protection.

System Evaluation Boundary

The evaluation boundary for the Laundry Facility includes concrete foundation, floor slab, roof slab, concrete block walls, steel roofing supports, doors, and roofing membrane elements associated with the built-up roofing.

System Intended Functions

Portions of the Laundry Facility are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Laundry Facility is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Laundry Facility can be found in the UFSAR, Section 9.10.2.1 and Section 9.10.2.2.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Laundry Facility is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-12, Laundry Facility.

The aging management review results for these component types are indicated in Table 3.5.2-12, Containments, Structures and Component Supports - Laundry Facility - Aging Management Evaluation.

2.4.1.13 Machine Shop

System Description

The Machine Shop is a multi-story, steel structure that is enclosed with metal siding and concrete masonry blocks. The steel structure is founded on a reinforced concrete mat foundation, which is founded on precast, prestressed concrete piles. The roof consists of steel framing that is covered by metal decking and built up roofing.

The Machine Shop is a nonsafety-related structure. No safety-related equipment or nonsafety-related equipment with the potential to affect safety-related equipment is located in the Machine Shop. The building houses fire suppression equipment credited for fire protection.

System Evaluation Boundary

The evaluation boundary for the Machine Shop includes structural bolting; concrete elements associated with the foundation, floor slabs, curbs, and pads; concrete block walls; steel elements associated with beams, columns, baseplates, bracing, wall panels, louvers, doors, stairways, railings, and roofing; and components associated with the built-up roofing.

System Intended Functions

Portions of the Machine Shop are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Machine Shop is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Machine Shop can be found in the UFSAR, Section 9.10.4.28.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Machine Shop is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-13, Machine Shop.

The aging management review results for these component types are indicated in Table 3.5.2-13, Containments, Structures and Component Supports - Machine Shop - Aging Management Evaluation.

2.4.1.14 Radwaste Facility

System Description

The Radwaste Facility consists of a multi-story reinforced concrete structure for the radwaste treatment equipment and a steel structure for non-radwaste services. The reinforced concrete structure is enclosed with concrete walls and a concrete roof slab (partly). A portion of the roof is constructed of roof steel framing structure and steel deck with built-up roof membrane. The grade floor (mat) and intermediate floors are constructed of concrete material. The steel structure is enclosed with metal siding above grade and built-up roof membrane on the steel deck, which is supported by steel structural framing.

The Radwaste Facility is a nonsafety-related structure that is outside of the protected area, north of the Station Blackout (AAC) Building, and does not abut any other structure. No safety-related equipment or nonsafety-related equipment with the potential to affect safety-related equipment is located in the Radwaste Facility. The building houses fire suppression equipment credited for fire protection.

System Evaluation Boundary

The evaluation boundary for the Radwaste Facility includes structural bolting, concrete elements associated with the foundation, floor slabs, pads, curbs, hatches, interior and exterior walls, concrete block walls, steel elements associated with the building beams, columns, baseplates, bracing, doors, flooring, wall panels, platforms, hatches, stairways, ladders, railings, and roofing, and roofing membrane elements associated with the built-up roofing.

System Intended Functions

Portions of the Radwaste Facility are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Radwaste Facility is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Radwaste Facility can be found in the UFSAR, Section 9.10.2.2.5 and Section 14.4.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Radwaste Facility is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-14, Radwaste Facility.

The aging management review results for these component types are indicated in Table 3.5.2-14, Containments, Structures and Component Supports - Radwaste Facility - Aging Management Evaluation.

2.4.1.15 SBO Building

System Description

The Station Blackout Building (also known as the AAC Building) is a one-story structure with a reinforced concrete foundation. The Station Blackout Building consists of concrete-grade floor slab and steel-framed structure with the lower portions of the exterior walls constructed of concrete and the upper portions of metal siding. The roof is constructed of metal decking covered with built-up roofing and concrete pavers. The Station Blackout Building is a nonsafety-related, non-seismic structure located outside the protected area, east of the Condensate Polishing Building and south of the Radwaste Facility. The building does not abut any other structure.

The Station Blackout Building houses the alternate AC diesel generator and its associated auxiliaries, which provide alternate power to the safe shutdown equipment in both Unit 1 and Unit 2 during a station blackout, and which provide power to the control room/emergency switchgear chillers in the event of a fire. The building also houses fire suppression equipment credited for fire protection.

System Evaluation Boundary

The evaluation boundary for the Station Blackout Building includes structural bolting, concrete elements associated with the foundation, walls, ceiling slabs, pads, curbs, and roofing slabs and pavers, concrete block walls, steel elements associated with the building beams, columns, baseplates, bracing, doors, flooring, wall panels and louvers, platforms, stairways, ladders, railings, and roofing, and roofing membrane elements associated with the built-up roofing.

System Intended Functions

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

UFSAR References

Additional details of the SBO Building can be found in the UFSAR, Section 8.4.6 and Section 9.10.2.2.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the SBO Building is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-15, SBO Building.

The aging management review results for these component types are indicated in Table 3.5.2-15, Containments, Structures and Component Supports - SBO Building - Aging Management Evaluation.

2.4.1.16 Service Building

System Description

The Service Building is adjacent to and south of the Auxiliary Building, but extends further to the east and west, and serves both Unit 1 and Unit 2.

The Service Building is a four-level structure, and includes the following rooms/cubicles: normal and emergency switchgear and relay rooms; battery rooms 1A, 1B, and 2A; mechanical equipment rooms 1, 2, and 3; cable vault; control room; Technical Support Center; diesel generator cubicles; and cable tray rooms.

The Service Building is founded on reinforced concrete on compacted soil. The flooring consists of slabs on grade and intermediate floors. Structural floor slabs are cast on permanent metal deck forms supported by structural steel framing. Reinforced concrete walls surround the cubicles requiring tornado missile protection. The Service Building houses the control room, which maintains an independent pressure boundary envelope for habitability during a design basis accident. The control room pressure boundary envelope includes the main control room (including control room annex area); emergency switchgear and relay rooms, safety-related battery rooms, associated stairwell, and mechanical equipment room 3.

The cubicles on the first two levels of the Service Building are bounded on all sides by concrete or concrete block. The cubicles on the top two levels are bounded by metal siding or concrete block walls and built-up roof. The exterior concrete block walls are covered outside with brick veneers. The brick veneer does not support an intended function and is not within-scope. Fire barriers are provided to protect safety-related equipment.

Portions of the Service Building are seismic class 1, including the emergency switchgear and relay rooms; battery rooms 1A, 1B, 2A; the cable vault; the control room; and the diesel generator rooms. Other portions, including mechanical equipment rooms 1 and 2; cable tray rooms; normal switchgear rooms; Technical Support Center; and stairwell; are all nonsafety-related structures within the Service Building. Mechanical equipment rooms 1 and 2 house the feedwater flow control valves, which are safety-related components. The cable tray rooms and normal switchgear rooms house electrical components that supply power during station blackout events. The Technical Support Center protects essential fire protection-related components, and the stairwell provides access to fire protection equipment.

System Evaluation Boundary

The evaluation boundary for the Service Building includes structural bolting, doors, flood dikes, concrete elements associated with the foundation, walls, floor slabs, hatches, pads, curbs, and roofing slabs, concrete block walls, steel elements associated with the beams, columns, baseplates, bracing, flooring, wall panels and louvers, platforms, stairways, ladders, railings, and roofing, and roofing membrane elements associated with the built-up roofing.

System Intended Functions

Portions of the Service Building perform the following safety-related functions: The Service Building includes seismic class 1 structural elements that provide support, shelter and protection for safety-related systems and components. Therefore, the Service Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Service Building provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function, and the integrity of nonsafety-related portions of the structure prevents collapse onto safety-related SSCs. Therefore, the Service Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Service Building 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, the Service Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Service Building can be found in the UFSAR, Section 9.10.4, Section 15.6, and Table 15.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Service Building is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-16, Service Building.

The aging management review results for these component types are indicated in Table 3.5.2-16, Containments, Structures and Component Supports - Service Building - Aging Management Evaluation.

2.4.1.17 Turbine Building

System Description

The Turbine Building is a steel-framed structure founded on reinforced concrete on compacted soil. The below-grade portions of the exterior walls are constructed of concrete, and the above-grade portions are constructed of metal siding. The roof consists of metal decking covered with built-up roofing.

The Turbine Building is bounded on the west side by the Office Building, on the east side by the Condensate Polishing Building. The south side of the Turbine Building is exposed to the atmosphere. The north side shares a common wall with a portion of the Service Building that contains safety-related equipment. The operating floor of the Turbine Building is an open area that serves both Unit 1 and Unit 2. Below the operating floor, a block wall separates Units 1 and 2.

The Turbine Building is separated from the safety-related portions of the Service Building by reinforced concrete walls. The Turbine Building has three levels. The operating floor is constructed of reinforced concrete supported on steel framing. Most of the areas on the mezzanine level and platforms are steel-framed with metal floor grating. The concrete slab on the mezzanine level over the component cooling heat exchanger is designed as a missile barrier. The grade slab supports safety-related equipment. Flood control sumps are located on the grade slab. Stairways between floors are constructed of metal grating.

The Turbine Building is a nonsafety-related structure that has been designed for tornado wind load. The building contains battery room 2B and mechanical equipment rooms 4 and 5, which are seismic class 1 structures that protect safety-related equipment:

<u>Battery Room 2B</u>

Battery room 2B is located on the Turbine Building ground floor. Battery room 2B houses safety-related batteries and is part of the control room pressure boundary envelope. Battery room 2B is a seismic class 1 structure that is bounded on all sides by concrete walls and a roof slab, which provide fire barriers.

Mechanical Equipment Room 4

Mechanical equipment room 4 is bounded on all sides by concrete walls and a roof slab, which provide fire barriers. A removable two-foot-high metal plate dike is located at the entrance to this mechanical equipment room to restrict Turbine Building floodwater from entering the room and potentially affecting the charging pumps' service water pumps. The charging pumps' service water pumps are separated by seismic, missile-protected, fire-rated walls, ceiling, and floor.

Mechanical Equipment Room 5

Mechanical equipment room 5 is located in the Unit 2 side of the Turbine Building and houses two chillers. One wall of the room is shared with the Turbine Building. Mechanical equipment room 5 is isolated from fires in other areas of the Turbine Building by fire barrier walls and doors. Equipment in the room is protected from Turbine Building flooding by a flood dike at the doors that provide access to the room. A flood barrier wall, separating the electrical equipment from the mechanical room and the Turbine Building sump, protects the electrical equipment.

Several safety-related cable trays are located at various elevations of the Turbine Building. The Unit 2 portion of the Turbine Building houses electrical cables and raceways that supply power during station blackout events. Fire barrier doors are provided to protect safety-related equipment. The exterior concrete block walls are covered outside with brick veneers. The brick veneer does not perform an intended function and is not within-scope.

System Evaluation Boundary

The evaluation boundary for the Turbine Building includes structural bolting, doors, flood dikes, concrete elements associated with the foundation, walls, floor slabs, hatches, pads, curbs, and roofing slabs, concrete block walls, steel elements associated with the beams, columns, baseplates, bracing, flooring, wall panels and louvers, missile shields, platforms, stairways, ladders, railings, and roofing, and roofing membrane elements associated with the built-up roofing.

System Intended Functions

Portions of the Turbine Building perform the following safety-related functions: The Turbine Building includes seismic class 1 structural elements that provide support, shelter and protection for safety-related systems and components. Therefore, the Turbine Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Turbine Building provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function, and the integrity of nonsafety-related portions of the structure prevents collapse onto safety-related SSCs. Therefore, the Turbine Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Turbine Building 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, the Turbine Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Turbine Building can be found in the UFSAR, Section 9.10.4.18, Section 9.10.4.19, Section 9.10.4.25, Section 9.10.4.27, Section 15.6, and Table 15.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Turbine Building is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-17, Turbine Building.

The aging management review results for these component types are indicated in Table 3.5.2-17, Containments, Structures and Component Supports - Turbine Building - Aging Management Evaluation.

2.4.1.18 Containment Spray Pump Building

System Description

The Containment Spray Pump Building for each unit consists of a containment spray area and a refueling water recirculating pump area. The building is adjacent to the Main Steam Valve House (which houses the auxiliary feedwater pumps) and Safeguards Building and is open to the Containment exterior wall. It is a reinforced concrete structure supported on a reinforced concrete mat foundation. The building has a metal deck roof and a reinforced concrete intermediate floor slab that are supported by structural steel framing.

System Evaluation Boundary

The evaluation boundary for the Containment Spray Pump Building includes the foundation mat, the internal structural members, external walls, and the roofing deck and membrane. Aluminum hatch covers and fixed louvers are also within the evaluation boundary.

System Intended Functions

Portions of the Containment Spray Pump Building perform the following safety-related functions: The Containment Spray Pump Building provides structural support, shelter and protection for safety-related SSCs required to provide the capability to shutdown the reactor and maintain it in a safe shutdown condition. Therefore, the Containment Spray Pump Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Containment Spray Pump Building provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Containment Spray Pump Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Containment Spray Pump Building are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Containment Spray Pump Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Containment Spray Pump Building can be found in the UFSAR, Section 9.10.4.13.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Containment Spray Pump Building is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-18, Containment Spray Pump Building.

The aging management review results for these component types are indicated in Table 3.5.2-18, Containments, Structures and Component Supports - Containment Spray Pump Building - Aging Management Evaluation.

2.4.1.19 Fire Pump House

System Description

The Fire Pump House is a free-standing, reinforced concrete structure in the southwest area of the yard. The pump house is divided into two separate cubicles by a reinforced concrete wall with a metal door. One cubicle is a seismic Class 1 reinforced concrete structure that houses the diesel-engine-driven fire pump. There are openings in the exterior wall that are protected with missile shields. The other cubicle which houses the electric-motor-driven fire pump, motor control center, surge tank, and two small water booster pumps, is not a seismic Class 1 structure. This cubicle is enclosed with a built-up metal deck roof and masonry block walls supported on spread footings.

System Evaluation Boundary

The evaluation boundary for the Fire Pump House includes the foundation, internal structural members, external concrete and masonry walls, and roofing deck and membrane. Aluminum fixed louvers are also within the evaluation boundary.

System Intended Functions

Portions of the Fire Pump House are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Fire Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Fire Pump House can be found in the UFSAR, Section 9.10.4.24.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Fire Pump House is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-19, Fire Pump House.

The aging management review results for these component types are indicated in Table 3.5.2-19, Containments, Structures and Component Supports - Fire Pump House - Aging Management Evaluation.

2.4.1.20 Fuel Oil Pump House

System Description

The Fuel Oil Pump House (common to both units), which shelters the diesel generator fuel oil supply pumps, is a reinforced concrete structure located at the northeast corner of the yard. The structure is divided into two cubicles by a reinforced concrete wall. The two cubicles are below grade and the roof slab is at the ground level with reinforced concrete and masonry block enclosures above the entrance areas. There is a concrete missile shield at the ground level to protect the fuel oil lines. A concrete missile-protected manhole adjacent to the Fuel Oil Pump House is an integral part of the pump house.

System Evaluation Boundary

The evaluation boundary for the Fuel Oil Pump House includes the foundation, internal structural members, external walls, roof slabs, and masonry block enclosures. The manhole adjacent to the Fuel Oil Pump House is also part of this evaluation boundary.

System Intended Functions

Portions of the Fuel Oil Pump House perform the following safety-related functions: The Fuel Oil Pump House is a safety-related structure and houses in-scope safety-related systems and components that meet the criteria of 10 CFR 54.4(a)(1). Therefore, the Fuel Oil Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Fuel Oil Pump House provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Fuel Oil Pump House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Fuel Oil Pump House are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Fuel Oil Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Fuel Oil Pump House can be found in the UFSAR, Section 9.10.4.23.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Fuel Oil Pump House is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-20, Fuel Oil Pump House.

The aging management review results for these component types are indicated in Table 3.5.2-20, Containments, Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation.

2.4.1.21 Main Steam Valve House

System Description

The Main Steam Valve House provides shelter for the main steam isolation valves and auxiliary feedwater pumps. It is a seismic Class 1, reinforced concrete structure supported by a reinforced concrete mat foundation adjacent to the Containment, the Containment Spray Pump Building, and the Safeguards Building. The mat foundation is founded on concrete filled steel pipe piles. The Main Steam Valve House has a roof slab and an intermediate floor slab. Both slabs are reinforced concrete structures supported by structural steel framing and are cast against permanent metal deck formwork. The openings of the roof slab, which are used for the removal of equipment, have missile shields. These openings and the missile shields are enclosed by a metal roof that is supported on steel trusses.

System Evaluation Boundary

The evaluation boundary for the Main Steam Valve House includes the foundation mat, steel pipe piles, the internal structural members, external walls, missile shields, slabs, and steel covers for roof openings.

System Intended Functions

Portions of the Main Steam Valve House perform the following safety-related functions: The Main Steam Valve House is a safety-related structure and houses in-scope safety-related systems and components that meet the criteria of 10 CFR 54.4(a)(1). Therefore, the Main Steam Valve House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Main Steam Valve House provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Main Steam Valve House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Main Steam Valve House are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the Main Steam Valve House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Main Steam Valve House can be found in the UFSAR, Section 2.4.6 and Section 9.10.4.13.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Main Steam Valve House is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-21, Main Steam Valve House.

The aging management review results for these component types are indicated in Table 3.5.2-21, Containments, Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation.

2.4.1.22 Safeguards Building

System Description

The Safeguards Building is a seismic Class 1 structure that houses the safeguards equipment, including the outside recirculating spray pumps, the low-head safety injection pumps, and the associated pipe tunnels. The Safeguards Building is a reinforced concrete structure supported on a reinforced concrete mat foundation adjacent to the Containment. The mat foundation is founded on concrete filled steel pipe piles. The building has three external side walls of reinforced concrete; the fourth side wall is a common wall with the Containment. The structure has a reinforced concrete roof with hatches for the removal of equipment. The Safeguards Building concrete structure is partially below grade. A pipe chase located on the missile barrier roof extends along the entire length of the roof. A concrete wall and a steel-framed metal deck roof enclose the pipe chase.

System Evaluation Boundary

The evaluation boundary for the Safeguards Building includes the foundation mat, steel pipe piles, the internal structural members, external walls, slabs, steel roof decking, and the concrete and steel pipe chase.

System Intended Functions

Portions of the Safeguards Building perform the following safety-related functions: The Safeguards Building is a safety-related structure and houses in-scope safety-related systems and components that meet the criteria of 10 CFR54.4(a)(1). Therefore, the Safeguards Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Safeguards Building provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Safeguards Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the Safeguards Building are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Safeguards Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Safeguards Building can be found in the UFSAR, Section 2.4.6 and Section 9.10.4.15.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Safeguards Building is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-22, Safeguards Building.

The aging management review results for these component types are indicated in Table 3.5.2-22, Containments, Structures and Component Supports - Safeguards Building - Aging Management Evaluation.

2.4.1.23 Buried Fuel Oil Tank Missile Barrier

System Description

Two underground fuel oil tanks supply fuel oil to three emergency diesel generators. A soil-supported reinforced concrete missile barrier protects the two tanks. The Buried Fuel Oil Tank Missile Barrier is located between the SPS unit 2 Containment and the discharge canal, west of the Fuel Oil Pump House.

System Evaluation Boundary

The evaluation boundary for the Buried Fuel Oil Tank Missile Barrier includes the reinforced concrete missile barrier.

System Intended Functions

The Buried Fuel Oil Tank Missile Barrier performs the following safety-related functions: The Buried Fuel Oil Tank Missile Barrier provides shelter and protection for safety-related SSCs. Therefore, the Buried Fuel Oil Tank Missile Barrier is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the Buried Fuel Oil Tank Missile Barrier can be found in the UFSAR, Section 8.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Buried Fuel Oil Tank Missile Barrier is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-23, Buried Fuel Oil Tank Missile Barrier.

The aging management review results for these component types are indicated in Table 3.5.2-23, Containments, Structures and Component Supports - Buried Fuel Oil Tank Missile Barrier - Aging Management Evaluation.

2.4.1.24 Chemical Addition Tank Foundation

System Description

The Chemical Addition Tank Foundation is a soil-supported reinforced concrete spread footing, located below grade. The chemical addition tank is attached with anchor bolts to a reinforced concrete pedestal, which is integral to the spread footing. The foundation also includes a reinforced concrete pump support. The skirt supported tank and pump bear on a layer of grout. The tank for each unit is located between its respective Containment and the Discharge Tunnel, south of the Emergency Condensate Makeup Tank.

System Evaluation Boundary

The evaluation boundary for the Chemical Addition Tank Foundation includes the reinforced concrete support pedestal, the reinforced concrete pump support, the anchor bolts, the grout, and the reinforced concrete spread footing.

The Chemical Addition Tank is evaluated in the containment spray system.

System Intended Functions

The Chemical Addition Tank Foundation performs the following safety-related function: The Chemical Addition Tank Foundation provides structural support for safety-related SSCs. Therefore, the Chemical Addition Tank Foundation is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the Chemical Addition Tank Foundation can be found in the UFSAR, Section 6.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Chemical Addition Tank Foundation is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-24, Chemical Addition Tank Foundation.

The aging management review results for these component types are indicated in Table 3.5.2-24, Containments, Structures and Component Supports - Chemical Addition Tank Foundation - Aging Management Evaluation.

2.4.1.25 Duct Banks

System Description

Duct Banks are underground reinforced concrete structures used for the routing of cables between plant structures and switchyard areas. 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 and transition boxes. Cable trenches have removable concrete covers, which are load rated and allow for access to cables inside. The transition boxes are typically located at the end of cable trenches and provide transition from the cable trench to an adjacent structure (e.g., building or duct bank).

System Evaluation Boundary

The evaluation boundary for the Duct Banks includes the reinforced concrete duct banks, cable trenches, and transition boxes. For duct banks, cable trenches, and transition boxes, 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: The Duct Banks provide support, shelter and protection for safety-related SSCs. Therefore, the Duct Banks are within the scope of license renewal in accordance with the criteria 10 CFR 54.4(a)(1).

Portions of the Duct Banks are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), ATWS (10 CFR 50.62), 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).

UFSAR References

Additional details of the Duct Banks can be found in the UFSAR, Section 8.4.6.

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 2.4.1-25, Duct Banks.

The aging management review results for these component types are indicated in Table 3.5.2-25, Containments, Structures and Component Supports - Duct Banks - Aging Management Evaluation.

2.4.1.26 Emergency Condensate Tank Foundations and Missile Barriers

System Description

The 100,000 gallon Emergency Condensate Makeup Tank is supported directly on compacted soil. Reinforced concrete completely encapsulates the tank above ground. The reinforced concrete walls are soil-supported on spread footings. A compressible material fills the void between the tank and the concrete. The tank for each unit is located between the Discharge Tunnel and its respective Containment.

The 110,000 gallon Emergency Condensate Storage Tank is soil-supported on a reinforced concrete mat foundation. A reinforced concrete missile barrier completely encapsulates the tank. The missile barrier has reinforced concrete walls, which are integral to the mat foundation, and a sloping, reinforced concrete roof. Anchor bolts attach the tank to the foundation. A reinforced concrete hatch, which provides access and missile protection for the tank, is installed in the roof. An enclosure which contains piping and level transmitters is located on the exterior wall. This enclosure also has reinforced concrete missile walls and a roof. The tank for each unit is located across the Discharge Tunnel from its respective Containment.

The 300,000 gallon Condensate Storage Tanks perform no subsequent license renewal intended function; therefore, the Condensate Storage Tank Foundations are not within the scope of subsequent license renewal. The tanks are located south of the west end of the Turbine Building.

System Evaluation Boundary

The evaluation boundary for the Emergency Condensate Storage Tank Foundation and Missile Barrier includes the 100,000 gallon Emergency Condensate Makeup Tank Missile Barrier (walls and roof) and Foundation and the compressible material between the tank and the concrete missile barrier.

The evaluation boundary also includes the 110,000 gallon Emergency Condensate Storage Tank Foundation, the reinforced concrete missile barrier (walls and roof), anchor bolts, a reinforced concrete hatch, and the reinforced concrete enclosure that contains piping and level transmitters located on the exterior wall.

The emergency condensate makeup tank and the emergency condensate storage tank are evaluated with the condensate system.

System Intended Functions

The 110,000 gallon Emergency Condensate Storage Tank Foundation and Missile Barrier perform the following safety-related functions: The Emergency Condensate Storage Tank Foundation and Missile Barrier provide structural support, shelter and protection for safety-related SSCs. Therefore, the Emergency Condensate Storage Tank Foundation and Missile Barrier are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The 100,000 gallon Emergency Condensate Makeup Tank Foundation provides structural support, and shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Emergency Condensate Storage Tank Foundation and Missile Barrier are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The 110,000 gallon Emergency Condensate Storage Tank Foundation and Missile Barrier are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Emergency Condensate Storage Tank Foundation and Missile Barrier are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Emergency Condensate Tank Foundations and Missile Barriers can be found in the UFSAR, Section 10.3.5.3 and Section 14B.5.1.7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Emergency Condensate Tank Foundations and Missile Barriers is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-26, Emergency Condensate Tank Foundations and Missile Barriers.

The aging management review results for these component types are indicated in Table 3.5.2-26, Containments, Structures and Component Supports - Emergency Condensate Tank Foundations and Missile Barriers - Aging Management Evaluation.

2.4.1.27 Fire Protection and Domestic Water Tank Foundation

System Description

The Fire Protection/Domestic Water Tank Foundations are supported on well-tamped sand and gravel with an oiled-sand cushion between the tank and the backfill. To contain this material under the tanks, reinforced concrete ring walls, whose tops are approximately at grade, were constructed just outside the perimeter of the tank. The Fire Protection/Domestic Water Tank Foundations are located adjacent to the Fire Pump House, west of the Intake Canal.

System Evaluation Boundary

The evaluation boundary for the Fire Protection/Domestic Water Tank Foundations includes the reinforced concrete ring walls constructed just outside the perimeter of the tank.

The Fire Protection/Domestic Water Tank is evaluated in the fire protection system.

System Intended Functions

The Fire Protection/Domestic Water Tank Foundations are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Fire Protection/Domestic Water Tank Foundations are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Fire Protection and Domestic Water Tank Foundation can be found in the UFSAR, Section 9.10.2.2.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Fire Protection and Domestic Water Tank Foundation is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-27, Fire Protection and Domestic Water Tank Foundation.

The aging management review results for these component types are indicated in Table 3.5.2-27, Containments, Structures and Component Supports - Fire Protection and Domestic Water Tank Foundation - Aging Management Evaluation.

2.4.1.28 Fuel Oil Line Missile Barrier

System Description

Where practicable, the fuel oil lines are buried sufficiently deep that the covering soil provides an adequate missile barrier. As they exit the Fuel Oil Pump House and cross over the SPS unit 2 Discharge Tunnel, the fuel oil lines are protected with a reinforced concrete missile barrier, which is soil-supported with its top at grade.

A bridge/missile barrier, consisting of a reinforced concrete slab resting on a steel plate, protects the fuel oil lines where they are routed over the top of the enclosed concrete liquid waste trench on their way to the emergency diesel generator room. The bridge rests on reinforced concrete spread footings.

In 1995, a design change was implemented to replace a significant portion of the fuel oil lines. Where required to protect these lines from external or internal missiles, the lines were either encased in or protected by reinforced concrete and steel missile barriers.

System Evaluation Boundary

The evaluation boundary for the Fuel Oil Line Missile Barriers includes the reinforced concrete slab over the fuel oil lines as they exit the Fuel Oil Pump House and cross over the SPS unit 2 Discharge Tunnel and the reinforced concrete slab resting on a steel plate and supported on reinforced concrete spread footings that protects the fuel oil lines where they are routed over the top of the liquid waste trench on their way to the emergency diesel generator room. Also included in the evaluation boundary are the reinforced concrete and steel missile barriers constructed as a result of the 1995 design change.

System Intended Functions

The Fuel Oil Line Missile Barriers perform the following safety-related functions: The Fuel Oil Line Missile Barriers provide shelter and protection for safety-related SSCs. Therefore, the Fuel Oil Line Missile Barriers are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the Fuel Oil Line Missile Barrier can be found in the UFSAR, Section 8.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Fuel Oil Line Missile Barrier is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-28, Fuel Oil Line Missile Barrier.

The aging management review results for these component types are indicated in Table 3.5.2-28, Containments, Structures and Component Supports - Fuel Oil Line Missile Barrier - Aging Management Evaluation.

2.4.1.29 Fuel Oil Storage Tank Dike

System Description

The Fuel Oil Storage Tank Dike is a reinforced concrete wall, sized to contain the entire capacity of the above-ground fuel oil tank. The dike is attached below grade to a soil-supported reinforced concrete spread footing. The Fuel Oil Storage Tank Dike is located between the SPS unit 2 Containment and the Discharge Canal.

System Evaluation Boundary

The evaluation boundary for the Fuel Oil Storage Tank Dike includes the reinforced concrete wall and the reinforced concrete spread footing.

System Intended Functions

The Fuel Oil Storage Tank Dike is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Fuel Oil Storage Tank Dike is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Fuel Oil Storage Tank Dike can be found in the UFSAR, Section 9.10.4.23.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Fuel Oil Storage Tank Dike is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-29, Fuel Oil Storage Tank Dike.

The aging management review results for these component types are indicated in Table 3.5.2-29, Containments, Structures and Component Supports - Fuel Oil Storage Tank Dike - Aging Management Evaluation.

2.4.1.30 Manholes

System Description

Manholes are reinforced concrete structures buried underground that are supported on compacted backfill. Manhole access openings, which allow personnel access, occur approximately at grade level. Safety-related manhole openings are protected with missile barrier, steel manway covers.

System Evaluation Boundary

The evaluation boundary for Manholes includes the reinforced concrete structures, missile barrier, steel manway covers, ladders, and platforms.

System Intended Functions

The Manholes perform the following safety-related functions: The Manholes provide support, shelter and protection for safety-related SSCs. Therefore, the Manholes are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Manholes provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Manholes are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

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

UFSAR References

Additional details of the Manholes can be found in the UFSAR, Section 18.1.4.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Manholes.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-30, Manholes.

The aging management review results for these component types are indicated in Table 3.5.2-30, Containments, Structures and Component Supports - Manholes - Aging Management Evaluation.

2.4.1.31 Reactor Containment Subsurface Drainage System Access Shaft

System Description

The groundwater level external to the Containment is kept below the top surface of the containment foundation mat by pumps in a subsurface cubicle adjacent to the outside of the Containment. This cubicle is accessed by a reinforced concrete shaft from ground level.

System Evaluation Boundary

The evaluation boundary of the Reactor Containment Subsurface Drainage System Access Shaft includes the reinforced concrete shaft.

System Intended Functions

The Reactor Containment Subsurface Drainage System Access Shaft provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Reactor Containment Subsurface Drainage System Access Shaft is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

UFSAR References

Additional details of the Reactor Containment Subsurface Drainage System Access Shaft can be found in the UFSAR, Section 15.5.1.12.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Reactor Containment Subsurface Drainage System Access Shaft.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-31, Reactor Containment Subsurface Drainage System Access Shaft.

The aging management review results for these component types are indicated in Table 3.5.2-31, Containments, Structures and Component Supports - Reactor Containment Subsurface Drainage System Access Shaft - Aging Management Evaluation.

2.4.1.32 Refueling Water Storage Tank Foundation

System Description

The Refueling Water Storage Tank Foundation is a reinforced concrete mat with an oiled-sand cushion between the tank and the mat. Black caulk is used to contain the oiled-sand under the tanks, Anchor bolts attach the tank to the foundation. The attachment plates for the anchor bolts bear on a layer of grout. The mat foundation is supported on concrete-filled steel pipe piles. The tank for each unit is located between the Discharge Tunnel and its respective Containment, south of the Emergency Condensate Makeup Tank.

System Evaluation Boundary

The evaluation boundary for the Refueling Water Storage Tank Foundation includes the reinforced concrete mat foundation, anchor bolts, the grout and the concrete-filled steel pipe piles.

The Refueling Water Storage Tank is evaluated in the containment spray system.

System Intended Functions

The Refueling Water Storage Tank Foundation performs the following safety-related functions: The Refueling Water Storage Tank Foundation provides structural support for safety-related SSCs. Therefore, the Refueling Water Storage Tank Foundation is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Refueling Water Storage Tank Foundation is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Refueling Water Storage Tank Foundation is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Refueling Water Storage Tank Foundation can be found in the UFSAR, Section 2.4.6, and Section 6.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Refueling Water Storage Tank Foundation is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-32, Refueling Water Storage Tank Foundation.

The aging management review results for these component types are indicated in Table 3.5.2-32, Containments, Structures and Component Supports - Refueling Water Storage Tank Foundation - Aging Management Evaluation.

2.4.1.33 SBO Structures for Offsite Power

System Description

The SBO recovery path from offsite power is supplied to the station by 34.5kV circuits originating in the switchyard. The switchyard contains reinforced concrete foundations and structural steel that support the 34.5kV breakers and disconnects that supply the Reserve Station Service Transformers (RSSTs). Control houses in the switchyard, which contain the controls for the breakers, are constructed of concrete masonry walls with reinforced concrete footings, and steel roof framing and decking. Reinforced concrete trenches are used to route cables from the control houses to the 34.5kV breakers.

The electrical distribution system cables associated with the offsite SBO recovery path are routed from the switchyard to the RSSTs via direct buried cable trenches, manholes, duct banks, and wood distribution poles.

The RSSTs are supported by reinforced concrete foundations, which are surrounded by a reinforced concrete dike, and separated by reinforced concrete walls. The electrical distribution system cables in this area are supported by steel that is attached to the concrete walls adjacent to the transformers or from concrete foundations.

From the RSSTs, the electrical distribution system is routed to the Turbine Building via tubular bus supported by steel structures mounted to reinforced concrete foundations. Cables attached to the tubular bus are then routed via cable trays supported from the Turbine Building to the normal switchgear room, which is located in the Service Building.

System Evaluation Boundary

The evaluation boundary for the SBO Structures for Offsite Power includes the steel, concrete, masonry, and wooden structures, except as noted below, that protect and/or support the electrical distribution system (e.g., cables, breakers, and switches) associated with the offsite SBO recovery path from the switchyard, through the RSSTs, and up to but not including the Turbine Building.

Structures not included in the evaluation boundary of the SBO Structures for Offsite Power are duct banks and trenches; manholes; and transformer fire walls and dikes. These structures are evaluated in their respective sections with Yard Structures.

The Turbine Building and the Service Building are evaluated with Miscellaneous Structures.

System Intended Functions

The SBO Structures for Offsite Power are relied upon for compliance with regulations for Station Blackout (10 CFR 50.63). Therefore, the SBO Structures for Offsite Power are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the SBO Structures for Offsite Power can be found in the UFSAR, Section 8.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the SBO Structures for Offsite Power is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-33, SBO Structures for Offsite Power.

The aging management review results for these component types are indicated in Table 3.5.2-33, Containments, Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation.

2.4.1.34 Security Lighting Poles

System Description

A post-fire emergency lighting system provides illumination for all areas needed for operation and/or monitoring of safe shutdown equipment, and to assure access/egress routes thereto, after a postulated fire in accordance with the requirements of 10 CFR 50 Appendix R, Section III.J. Eight direct buried reinforced concrete Security Lighting Poles support this emergency lighting along the west, north, and east sides of the protected area.

System Evaluation Boundary

The evaluation boundary for the Security Lighting Poles includes eight reinforced concrete poles along the west, north, and east sides of the powerhouse.

System Intended Functions

The Security Lighting Poles are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Security Lighting Poles are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Security Lighting Poles can be found in the UFSAR, Section 8.4.5 and Section 9.10.2.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Security Lighting Poles is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-34, Security Lighting Poles.

The aging management review results for these component types are indicated in Table 3.5.2-34, Containments, Structures and Component Supports - Security Lighting Poles - Aging Management Evaluation.

2.4.1.35 Transformer Firewalls and Dikes

System Description

The main and station service transformers and the reserve station service transformers firewalls are reinforced concrete walls between the transformers that separate the transformers to prevent the spread of fire. The dikes surrounding the transformers are reinforced concrete walls sized to contain the full volume of oil from a transformer in order to prevent the oil from spreading. The dike walls are embedded in soil, and the firewalls are attached below grade to soil-supported reinforced concrete spread footings. The main and service transformers are located along the south side of the Turbine Building. The reserve station service transformers are located between the High Level Intake Structures.

System Evaluation Boundary

The evaluation boundary for the Transformer Firewalls and Dikes includes the reinforced concrete firewalls, dikes, and spread footings surrounding and separating the main and station service transformers and the reserve station service transformers.

System Intended Functions

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

UFSAR References

Additional details of the Transformer Firewalls and Dikes can be found in the UFSAR, Section 9.10.4.22.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawing for the Transformer Firewalls and Dikes is listed below:

11448-SLRY-1H

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-35, Transformer Firewalls and Dikes.

The aging management review results for these component types are indicated in Table 3.5.2-35, Containments, Structures and Component Supports - Transformer Firewalls and Dikes - Aging Management Evaluation.

2.4.1.36 Component Supports

System Description

Component Supports for mechanical and electrical components are an integral part of all plant systems. The majority of these supports are not uniquely identified; however, all 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 supports for mechanical and electrical components within the structures that are in-scope for subsequent license renewal. Component Supports for NSSS equipment are evaluated separately. The remaining structural supports are addressed in this section, including supports and anchorage for the following:

- ASME Class 2 and Class 3 piping and components
- Cable trays, conduit, HVAC ducts, tubetracks, 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 is 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.

Steel elements, such as beams, columns, baseplates, bracing, stairs, platforms, grating, decking, and ladders are evaluated with the applicable buildings.

System Evaluation Boundary

The evaluation boundary for Component Supports includes structural supports for all mechanical and electrical components that are within the scope of subsequent license renewal and for all mechanical and electrical components that are not within the scope of subsequent license renewal but are located in buildings that contain safety-related SSCs. These supports include bolting, grout, spring supports, sliding surfaces, and steel 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.

System Intended Functions

Portions of the Component Supports perform the following safety-related functions: The Component Supports provide structural support, shelter and protection for safety-related SSCs. Therefore, the Component Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Component Supports provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Component Supports are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the 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, the Component Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Component Supports can be found in the UFSAR, Table 15.2-1.

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 2.4.1-36, Component Supports.

The aging management review results for these component types are indicated in Table 3.5.2-36, Containments, Structures and Component Supports - Component Supports - Aging Management Evaluation.

2.4.1.37 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:

- Fire barriers: fire barrier seals, fire stops, fire wraps, coatings, and radiant energy shields
- Electrical enclosures
- Penetration sleeves and seals
- Seismic gap filler material and covers

Fire barriers are located in safety and nonsafety buildings to protect equipment within the scope of subsequent license renewal from fire.

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.

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 (rattlespaces) are provided between adjacent structures to allow for relative motion between the structures. Although there are different configurations, the seismic gaps are arranged to prevent material from entering the gap space since the intrusion of foreign materials may impede the relative motion of adjacent structures. In most configurations, the seismic gaps are covered by structural angles or other elements such as elastomer seals, and the seismic gaps are filled with a compressible material. At certain locations the seismic covers function as fire barriers.

System Evaluation Boundary

The evaluation boundary for Miscellaneous Structural Commodities includes the fire barriers, electrical enclosures, penetration sleeves, penetration seals, seismic gap filler material, and seismic gap covers in the buildings and structures that are within the scope of subsequent license renewal.

Fire dampers are evaluated with the ventilation systems. Fire barrier walls, floors, and ceilings are evaluated with the individual structures in which they are installed.

System Intended Functions

Portions of the Miscellaneous Structural Commodities perform the following safety-related functions: The Miscellaneous Structural Commodities provide structural support, shelter and protection for safety-related SSCs. Therefore, the Structural Commodities are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Portions of the Miscellaneous Structural Commodities provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Miscellaneous Structural Commodities are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Portions of the 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, the Component Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Miscellaneous Structural Commodities can be found in the UFSAR, Section 7.7.2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the Miscellaneous Structural Commodities.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-37, Miscellaneous Structural Commodities.

The aging management review results for these component types are indicated in Table 3.5.2-37, Containments, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation.

2.4.1.38 NSSS Supports

System Description

The Nuclear Steam Supply System (NSSS) equipment supports are the plant structures and components that support the following reactor coolant system equipment and restrain it to the surrounding Containment:

Reactor Vessel Support

The reactor vessel is supported by six sliding foot assemblies mounted on the neutron shield tank. The support feet are designed to restrain lateral and rotational movement of the reactor vessel while allowing thermal expansion. The neutron shield tank is a double-walled cylindrical structure that transfers the loadings to the heavy reinforced-concrete mat of the Containment. The tank also serves to minimize gamma and neutron heating of the primary concrete shield, and to attenuate neutron radiation outside of the primary shield to acceptable limits.

Sliding support blocks mounted on top of the shield tank support the reactor vessel. These sliding support blocks permit radial thermal expansion of the reactor vessel, while preventing translation, rotation, or uplifting. The support blocks are also designed to adjust to the correct height for plumbing the reactor vessel and for distributing the load properly among the six supports.

Reactor Coolant Pump Support

The reactor coolant pumps are supported by a four-legged suspended structure. The supports do not have any heavy section intersecting member weldments.

Steam Generator Support

The steam generator support consists of two (upper and lower) cast rings and associated suspension rods, lateral restraints and snubbers. The lower ring, which carries the steam generator weight, is suspended by means of three pipe columns. Hydraulic snubber cylinders and rigid lateral guides connect the upper casting to the steam generator cubicle structure to allow guided thermal expansion of the steam generator outward from the reactor during normal operation, while resisting movement during seismic and pipe break conditions. The supports do not have any heavy section intersecting member weldments.

Pressurizer Support

The pressurizer vessel is mounted in a rigid support ring girder suspended by three hanger columns from above. Antisway brackets are welded to the shell of the pressurizer to accommodate shear blocks on the ring; the ring girder is laterally supported by a reinforcement plate attached to embedments in the concrete structure. In addition, lateral support for dynamic loads is provided near the vessel’s center of gravity by four gapped restraints at lugs on the pressurizer which transmit the loads into baseplates on the concrete floor. The lateral gapped restraints and hanger shear blocks and reinforcement plate are able to take all incident loads while allowing the pressurizer vessel to expand radially and vertically.

System Evaluation Boundary

The evaluation boundary for the NSSS Supports includes all supports for Nuclear Steam Supply System components. The evaluation boundary for each nuclear steam supply system support lies between the integral attachment on piping and equipment being supported and its Containment concrete supporting structure.

Specifically:

- Pins, bolting, and other removable hardware that are part of the connection to the NSSS equipment integral attachment have been evaluated with the nuclear steam supply system equipment supports.
- Spring supports, sliding surfaces, stainless steel elements, steel elements.
- Exposed portions of the embedded components (i.e. end portion of threaded anchor and nut) and grout are evaluated with the nuclear steam supply system equipment supports.
- Concrete supporting structures (including the embedded portion of threaded anchor) are evaluated with the Containment.
- Integral attachments for the nuclear steam supply system piping and equipment are evaluated for aging management with the specific nuclear steam supply system equipment.
- Snubbers are active components and not subject to aging management.

System Intended Functions

Portions of the NSSS Supports perform the following safety-related function: The NSSS Supports provide structural support for safety-related SSCs. Therefore, the NSSS Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the NSSS Supports can be found in the UFSAR, Section 15.6.2, Figure 15.6-1, Figure 15.6-2, Figure 15.6-3, Figure 15.6-4, Table 15.6-1, and Table 15.6-2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawing for the NSSS Supports.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-38, NSSS Supports.

The aging management review results for these component types are indicated in Table 3.5.2-38, Containments, Structures and Component Supports - NSSS Supports - Aging Management Evaluation.

Screening Results Tables: Containment, Structures and Component Supports

Table 2.4.1-1 Containment

Structural Member	Intended Function(s)
Bolting	Structural Support
Caulking and sealants	Enclosure Protection, Pressure Boundary
Concrete blocks (shielding)	Enclosure Protection
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Jet Impingement Shield, Missile Barrier, Pressure Boundary, Structural Support
Concrete missile barrier	Enclosure Protection, Missile Barrier, Structural Support
Containment liner	Pressure Boundary, Structural Support
Containment sump liner	Pressure Boundary, Structural Support
Door locking mechanism	Pressure Boundary, Structural Support
Embedded steel	Structural Support
Equipment hatch	Enclosure Protection, Missile Barrier, Pressure Boundary, Structural Support
Equipment hatch air lock doors	Enclosure Protection, Missile Barrier, Pressure Boundary, Structural Support
Fuel transfer tube enclosure protection shield	Enclosure Protection, Structural Support
Grout	Structural Support
Hinges and pins	Pressure Boundary, Structural Support
O-rings	Pressure Boundary, Structural Support
Penetrations (electrical)	Pressure Boundary, Structural Support

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-1 Containment

Structural Member	Intended Function(s)
Penetrations (mechanical)	Enclosure Protection, Pressure Boundary, Structural Support
Personnel hatch	Enclosure Protection, Pressure Boundary, Structural Support
Porous concrete	Structural Support
Reactor cavity liner	Pressure Boundary, Structural Support
Reactor cavity seal ring	Pressure Boundary, Structural Support
Service Level I coatings	Coating Integrity
Steel elements	Structural Support
Steel missile shields	Missile Barrier, Structural Support
Waterproofing membrane	Enclosure Protection, Flood Barrier

The AMR results for these component types are indicated in Table 3.5.2-1, Containments, Structures and Component Supports - Containment - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-2 Auxiliary Building Structure

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Concrete hatches	Enclosure Protection, Missile Barrier, Structural Support
Doors	Fire Barrier, Missile Barrier, Structural Support
Embedded steel	Structural Support
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Metal siding walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Leakage Boundary (Spatial), Structural Support
Steel hatches	Enclosure Protection, Structural Support
Steel missile shields	Enclosure Protection, Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-2, Containments, Structures and Component Supports - Auxiliary Building Structure - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-3 Discharge Canal

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support
Earthen dike and embankment	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-3, Containments, Structures and Component Supports - Discharge Canal - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-4 Intake Canal

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Missile Barrier, Structural Support
Earthen dike and embankment	Source of Cooling, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-4, Containments, Structures and Component Supports - Intake Canal - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-5 Fuel Building Structure

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Flood Barrier, Missile Barrier, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Metal siding	Enclosure Protection
Pipe piles	Structural Support
Roofing membrane	Enclosure Protection
Spent fuel pool liner plates	Enclosure Protection, Pressure Boundary, Structural Support
Stainless steel elements	Enclosure Protection, Structural Support
Steel elements	Enclosure Protection, Structural Support
Steel gates or doors	Enclosure Protection, Pressure Boundary, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-5, Containments, Structures and Component Supports - Fuel Building Structure - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-6 Discharge Tunnel and Seal Pit

Structural Member	Intended Function(s)
Concrete elements	Water Barrier

The AMR results for these component types are indicated in Table 3.5.2-6, Containments, Structures and Component Supports - Discharge Tunnel and Seal Pit - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-7 High Level Intake Structure

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Water Barrier, Fire Barrier, Missile Barrier, Source of Cooling, Structural Support
Gaskets (seal plates)	Flood Barrier
Masonry block walls	Structural Support
Steel elements	Filtration, Flood Barrier, Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-7, Containments, Structures and Component Supports - High Level Intake Structure - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-8 Low Level Intake Structure

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Water Barrier, Fire Barrier, Flood Barrier, Missile Barrier, Source of Cooling, Structural Support
Gaskets (gate seals)	Flood Barrier
Masonry block walls	Fire Barrier, Structural Support
Steel elements	Flood Barrier, Missile Barrier, Structural Support
Trash racks	Filtration

The AMR results for these component types are indicated in Table 3.5.2-8, Containments, Structures and Component Supports - Low Level Intake Structure - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-9 Black Battery Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-9, Containments, Structures and Component Supports - Black Battery Building - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-10 Central Alarm Station

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-10, Containments, Structures and Component Supports - Central Alarm Station - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-11 Condensate Polishing Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-11, Containments, Structures and Component Supports - Condensate Polishing Building - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-12 Laundry Facility

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-12, Containments, Structures and Component Supports - Laundry Facility - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-13 Machine Shop

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-13, Containments, Structures and Component Supports - Machine Shop - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-14 Radwaste Facility

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-14, Containments, Structures and Component Supports - Radwaste Facility - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-15 SBO Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-15, Containments, Structures and Component Supports - SBO Building - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-16 Service Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary, Structural Support
Doors	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary
Flood dikes	Flood Barrier
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Leakage Boundary (Spatial), Structural Support

The AMR results for these component types are indicated in Table 3.5.2-16, Containments, Structures and Component Supports - Service Building - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-17 Turbine Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary, Structural Support
Doors	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary
Flood dikes	Flood Barrier
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-17, Containments, Structures and Component Supports - Turbine Building - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-18 Containment Spray Pump Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection, Structural Support
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Missile Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-18, Containments, Structures and Component Supports - Containment Spray Pump Building - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-19 Fire Pump House

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Masonry block	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-19, Containments, Structures and Component Supports - Fire Pump House - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-20 Fuel Oil Pump House

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Masonry block walls	Enclosure Protection, Flood Barrier, Structural Support
Steel elements	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-20, Containments, Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-21 Main Steam Valve House

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Jet Impingement Shield, Missile Barrier, Structural Support
Pipe piles	Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-21, Containments, Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-22 Safeguards Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Pipe piles	Structural Support
Steel elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-22, Containments, Structures and Component Supports - Safeguards Building - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-23 Buried Fuel Oil Tank Missile Barrier

Structural Member	Intended Function(s)
Concrete element	Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-23, Containments, Structures and Component Supports - Buried Fuel Oil Tank Missile Barrier - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-24 Chemical Addition Tank Foundation

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Structural Support
Grout	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-24, Containments, Structures and Component Supports - Chemical Addition Tank Foundation - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-25 Duct Banks

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support
Pull boxes	Enclosure Protection

The AMR results for these component types are indicated in Table 3.5.2-25, Containments, Structures and Component Supports - Duct Banks - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-26 Emergency Condensate Tank Foundations and Missile Barriers

Structural Member	Intended Function(s)
Bolting	Structural Support
Compressible seal	Enclosure Protection
Concrete elements	Enclosure Protection, Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-26, Containments, Structures and Component Supports - Emergency Condensate Tank Foundations and Missile Barriers - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-27 Fire Protection and Domestic Water Tank Foundation

Structural Member	Intended Function(s)
Concrete element	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-27, Containments, Structures and Component Supports - Fire Protection and Domestic Water Tank Foundation - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-28 Fuel Oil Line Missile Barrier

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Missile Barrier, Structural Support
Steel element	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-28, Containments, Structures and Component Supports - Fuel Oil Line Missile Barrier - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-29 Fuel Oil Storage Tank Dike

Structural Member	Intended Function(s)
Concrete elements	Flood Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-29, Containments, Structures and Component Supports - Fuel Oil Storage Tank Dike - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-30 Manholes

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Missile Barrier, Structural Support
Steel elements	Missile Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-30, Containments, Structures and Component Supports - Manholes - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-31 Reactor Containment Subsurface Drainage System Access Shaft

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-31, Containments, Structures and Component Supports - Reactor Containment Subsurface Drainage System Access Shaft - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-32 Refueling Water Storage Tank Foundation

Structural Member	Intended Function(s)
Bolting	Structural Support
Caulking and sealants	Enclosure Protection
Concrete element	Structural Support
Grout	Structural Support
Pipe piles	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-32, Containments, Structures and Component Supports - Refueling Water Storage Tank Foundation - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-33 SBO Structures for Offsite Power

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Concrete masonry walls	Structural Support
Steel elements	Structural Support
Wooden poles	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-33, Containments, Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-34 Security Lighting Poles

Structural Member	Intended Function(s)
Concrete elements	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-34, Containments, Structures and Component Supports - Security Lighting Poles - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-35 Transformer Firewalls and Dikes

Structural Member	Intended Function(s)
Concrete elements	Fire Barrier, Flood Barrier, Structural Support

The AMR results for these component types are indicated in Table 3.5.2-35, Containments, Structures and Component Supports - Transformer Firewalls and Dikes - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-36 Component Supports

Component Type	Intended Function(s)
Aluminum elements	Enclosure Protection, Structural Support
Bolting	Structural Support
Grout	Structural Support
Sliding surfaces	Structural Support
Spring support	Structural Support
Stainless steel elements	Structural Support
Steel elements	Enclosure Protection, Structural Support
Vibration isolation elements	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-36, Containments, Structures and Component Supports - Component Supports - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-37 Miscellaneous Structural Commodities

Component Type	Intended Function(s)
Bolting	Structural Support
Electrical Enclosures	Enclosure Protection, Structural Support
Fire barrier seals	Fire Barrier
Fire stops	Fire Barrier
Fire wraps and coatings	Fire Barrier
Penetration seals	Enclosure Protection, Pressure Boundary
Penetration sleeves	Structural Support
Radiant energy shields	Fire Barrier
Seismic gap covers	Enclosure Protection, Fire Barrier
Seismic gap filler material	Enclosure Protection

The AMR results for these component types are indicated in Table 3.5.2-37, Containments, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.4.1-38 NSSS Supports

Component Type	Intended Function(s)
Bolting	Structural Support
Grout	Structural Support
Sliding surfaces	Structural Support
Stainless steel elements	Structural Support
Steel elements	Structural Support

The AMR results for these component types are indicated in Table 3.5.2-38, Containments, Structures and Component Supports - NSSS Supports - Aging Management Evaluation.

See Table 2.1.5-1 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. This figure also includes the Alternate AC power source used during the SBO coping period. 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

The first step in the screening process for electrical components and commodities is to identify electrical components and commodities within the electrical, I&C and mechanical systems based on plant design documents.

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. The following electrical components and commodity groups were determined to meet the screening criteria of 10 CFR 54.21(a)(1)(i):

- 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
    - 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
    - Cable tie-wraps
    - Uninsulated ground conductors
- Metal Enclosed Bus
- High Voltage Insulators
- Containment Electrical and I&C Penetrations

Elimination of Electrical Components with No License Renewal Intended Functions

The following electrical components (cable tie-wraps and uninsulated ground conductors) were determined to not have a license renewal intended function and were eliminated from the electrical commodity groups:

Cable Tie-Wraps

Cable tie-wraps are used in cable installations as cable ties. Cable tie-wraps hold groups of cables together for restraint and ease of maintenance. Cable tie-wraps are used to bundle wires and cables together to keep the wire and cable runs neat and orderly. Cable tie-wraps are used to restrain wires and cables within raceways to facilitate cable installation. There are no current license basis requirements that cable tie-wraps remain functional during and following design basis events. Cable tie-wraps are not credited for maintaining cable ampacity, ensuring maintenance of cable minimum bending radius, or maintaining cables within vertical raceways. The seismic qualification of cable trays does not credit the use of cable tie-wraps. Cable tie-wraps are not credited in the design basis in terms of any 10 CFR 54.4 intended function. Therefore, cable tie-wraps are not within the scope of subsequent license renewal and are not subject to aging management review.

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 Criteria 10 CFR 54.21(a)(1)(ii) to Electrical Commodities and Components

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 54.21(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 the criteria of 10 CFR 54.21(a)(1)(ii) are electrical and I&C components and commodities included in the Environmental Qualification 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 the screening criteria of 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.

A portion of the electrical penetrations are environmentally qualified. These electrical penetrations are evaluated as a time-limited aging analysis and are managed by the *Environmental Qualification of Electric Equipment* program (B3.3). For the remainder of the electrical penetrations, the electrical continuity of electrical penetration pigtails and associated connections that could potentially be exposed to an adverse localized environment is included in the evaluation for the electrical insulation material for electrical cables and connections component group under the Cables and Connections commodity group in Section 2.5.1.1. The pressure boundary, and structural support intended functions of electrical penetrations are included in the evaluation for Containment in Section 2.4.1.1.

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 Cables and Connections

Component Group Description

The electrical commodity group identified as “Cables and Connections” includes the following electrical and I&C component groups:

- Cable connections (metallic parts)
- Connector contacts for electrical connections exposed to borated water leakage
- Electrical insulation material for electrical cables and connections
- 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

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.

<u>Cable Connection (Metallic Parts)</u>

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.

<u>Connector Contacts for Electrical Connections Exposed to Borated Water Leakage</u>

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.

<u>Electrical Insulation Material for Electrical Cables and Connections</u>

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:

- Insulation material for electrical cables and connections
- Insulation material for electrical cables and connections used in instrumentation circuits
- Insulation material for electrical penetration pigtails
- Insulation material for inaccessible or below ground medium-voltage cable
- Insulation material for inaccessible or below ground I&C cable
- Insulation material for Inaccessible or below ground low-voltage power cable

Underground insulated medium-voltage cable that is part of the SBO offsite power recovery path and connects the switchyard breakers to overhead conductors (cable or bus) that feed the reserve station service transformers (RSSTs) is included within the scope of subsequent license renewal.

<u>Fuse Holder - Not Part of Active Equipment (Insulation Material)</u>

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.

<u>Fuse Holder - Not Part of Active Equipment (Metallic Clamps)</u>

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.

<u>Switchyard Bus and Connections</u>

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 following an SBO event. The boundary for these power feeds is the first circuit breakers downstream of switchyard buses 5, 6, and 7, and their associated disconnect switches. These components include the 3.5" aluminum switchyard bus, bare aluminum cable, and termination devices that connect active components (disconnect switches and 34.5 kV circuit breakers) from switchyard buses 5, 6, and 7 to the RSSTs.

Also included in the switchyard bus and connections component group is the 1" aluminum tube bus (switchyard bus) that connects RSST high voltage bushings to overhead and underground conductors from the 34.5 kV switchyard, the 5" aluminum tube bus (switchyard bus) from the low voltage side of the RSSTs to cable connections at the Turbine Building, and 2500 MCM bare aluminum cable that connects the RSST low voltage bushings to the 5" aluminum tube bus (switchyard bus). Although these components are within the station, 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 conductors component group includes the 34.5 kV overhead conductors that are credited for recovery of offsite power following an SBO event. These conductors are the 477 MCM All Aluminum Conductor overhead cables for the RSST A and B feed only. The RSST C feed is entirely underground.

Transmission Connections

The transmission connections component group includes the connections for the 34.5 kV transmission conductors that are credited for recovery of offsite power following an SBO event.

Component Group 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. 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 34.5 kV circuit breakers and associated disconnect switches downstream of 34.5 kV Buses 5, 6, and 7 and continue through the reserve station service transformers A, B, and C to transfer buses D, E, and F.

Stored Equipment

The cables and connections commodity group includes cable and terminal lugs stored in the warehouse at SPS 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 tray, conduit, structural supports, wooden poles, racks and panels, are assessed as part of the structural evaluation.

Component Group 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 supply electrical power, control and indication signals to nonsafety-related components that support safety-related functions. Therefore, cables and connections are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2). 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).

UFSAR References

Additional details of the cables and connections can be found in the UFSAR, Section 8.2, Section 8.3, and Section 8.4.6.

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 2.5.1-1, Cables and Connections.

The aging management review results for these component types are indicated in Table 3.6.2-1, Electrical and Instrumentation and Controls - Cables and Connections - Aging Management Evaluation

2.5.1.2 High Voltage Insulators

Component Group 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. Polymer insulators are not used in the SBO offsite power recovery path. 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.

Component Group Boundary

The high-voltage insulators commodity group includes SBO offsite power recovery path insulators that support 34.5 kV switchyard bus and transmission conductors from switchyard buses 5, 6, and 7 to the reserve station service transformers, and 4,160V overhead switchyard bus from the reserve station service transformers to cables located at the turbine buildings. The boundary for the SBO offsite power recovery path is the first circuit breakers downstream of switchyard buses 5, 6, and 7, and their associated disconnect switches. These insulators operate at medium-voltage (69 kV or less), but are similar in design and application to insulators operating at high-voltage. Therefore, insulators that are credited for restoration of offsite power following an SBO event are within-scope for subsequent license renewal.

Components that support high voltage insulators, for example structural supports and wooden poles, are assessed as part of the structural evaluation.

Component Group 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).

UFSAR References

None

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 2.5.1-2, High Voltage Insulators.

The aging management review results for these component types are indicated in Table 3.6.2-2, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation.

2.5.1.3 Metal Enclosed Bus

Component Group Description

The electrical commodity group identified as “Metal Enclosed Bus” includes the following component groups:

- Metal enclosed bus – bus and connection insulation
- Metal enclosed bus – bus and connections
- Metal enclosed bus – bus enclosure

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 only type of metal enclosed bus in-scope of subsequent license renewal is non-segregated phase bus. Metal enclosed bus is not included in the EQ Program. Therefore, metal enclosed bus meets the screening criteria for 10 CFR 54.21(a)(1)(ii) and is subject to aging management review.

Component Group Boundary

The metal enclosed bus commodity group includes the following sections of non-segregated phase buswork:

- MEB connecting Transfer Bus D switchgear cubicle 15D2 to Unit 2 Bus A switchgear cubicle 25A1
- MEB connecting Transfer Bus E switchgear cubicle 15E2 to Unit 2 Bus B switchgear cubicle 25B1
- MEB connecting Transfer Bus F switchgear cubicle 15F2 to Unit 2 Bus C switchgear cubicle 25C1
- SBO MEB connecting Bus 0L switchgear cubicle 05L3 to Transfer Bus D MEB
- SBO MEB connecting Bus 0L switchgear cubicle 05L1 to Transfer Bus E MEB
- MEB connecting emergency switchgear Bus 1H cubicle 15H8 to cubicle 15H9
- MEB connecting emergency switchgear Bus 1J cubicle 15J8 to cubicle 15J9
- MEB connecting emergency switchgear Bus 2H cubicle 25H8 to cubicle 25H9
- MEB connecting emergency switchgear Bus 2J cubicle 25J8 to cubicle 25J9
- MEB connecting transformer 1A2 to switchgear Bus 1A2 cubicle 14A2-7

Structural supports that support metal enclosed bus are assessed as part of the structural evaluation.

Component Group Intended Functions

Sections of Metal Enclosed Bus that perform the intended functions of “conducts electricity” and “insulates” supply electrical power to safety-related switchgear. Therefore, Metal Enclosed Bus is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1). Sections of Metal Enclosed Bus that perform the intended functions of “conducts electricity” and “insulates” supply power to nonsafety-related switchgear that supplies power to safety-related switchgear. Therefore, Metal Enclosed Bus is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2). Sections of Metal Enclosed Bus that perform the intended functions of “conducts electricity” and “insulates” are relied on for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, Metal Enclosed Bus is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

The Metal Enclosed Bus enclosure performs the intended function of “enclosure protection.”

UFSAR References

None

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the metal enclosed bus.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.5.1-3, Metal Enclosed Bus.

The aging management review results for these component types are indicated in Table 3.6.2-3, Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation.

Screening Results Tables: Electrical and Instrumentation and Controls Commodity Groups

Table 2.5.1-1 Cables and Connections

Component Type	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 Connections	Conducts Electricity

The AMR results for these component types are indicated in Table 3.6.2-1, Electrical and Instrumentation and Controls - Cables and Connections - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.5.1-2 High Voltage Insulators

Component Type	Intended Function(s)
High voltage insulators	Insulate

The AMR results for these component types are indicated in Table 3.6.2-2, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation.

See Table 2.1.5-1 for definitions of intended functions.

Table 2.5.1-3 Metal Enclosed Bus

Component Type	Intended Function(s)
Bus and connection insulation	Insulate
Bus and connections	Conducts Electricity
Bus enclosure	Enclosure Protection

The AMR results for these component types are indicated in Table 3.6.2-3, Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation.

See Table 2.1.5-1 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" (Reference 1.7-3).

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, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," (Reference 1.7-4) environments that were used when comparing the SPS 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 rows. 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 containment 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 row with the corresponding NUREG-2192 table row, 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 containment spray system, recirculation spray 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 2.1.5-1.

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 industry lettered notes and, if applicable, plant-specific numbered notes.

The standard industry 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 industry lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

<u>Table Usage</u>

Table 1

The reviewer evaluates each row 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 row are consistent with the material, environment, aging effect, and program(s) associated with the assigned NUREG-2191 row, 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 row within the table, the reviewer is able to 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 row, 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 row 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 40 years of plant operation. This includes explicit ASME Code, Section III, Class 1 analyses for piping and components and implicit ASME Code, Section III, Class 2 and 3 and ANSI B31.1 analyses for piping. 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

SPS 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.	Air with borated water leakage, System temperature up to 340 °C (644° F)
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
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.	Air, Condensation
Diesel exhaust	Gases, fluids, and particulates present in diesel engine exhaust.	Diesel exhaust

Table 3.0-1 Mechanical System Service Environments

SPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
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 (including Fyrquel, used in the electrohydraulic control system).	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,
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
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 rows 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

Table 3.0-1 Mechanical System Service Environments

SPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
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.	Neutron flux, 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. This name is also used to describe the environment for exterior surface of outdoor tank bottoms that are mounted on a concrete pad. SPS does not have a carbonate/bicarbonate environment that would promote cracking of steel in soil	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.	Treated borated water
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.	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, Steam, Treated water,

Table 3.0-1 Mechanical System Service Environments

SPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison [1]
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 rows 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)
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.	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

Note:

1. NUREG-2191 rows with environments of "Any" are cited where applicable, and environment equivalences are not listed in this table.

Intentionally Blank

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 Generator (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 Generator - 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:

- Crack growth
- 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)
- 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
- Cumulative fatigue damage
- 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:

- Cast austenitic stainless steel
- Copper alloy
- Copper alloy (>15 percent Zn)
- Fiberglass
- Stainless steel
- Steel
- Steel with internal coating
- Steel with stainless steel cladding
- Steel with stainless steel insert

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
- Concrete
- Gas
- Lubricating oil
- Reactor coolant
- Reactor coolant >250°C (>482°F)
- Treated borated water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the reactor coolant system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of fracture toughness
- 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 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)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)
- Water Chemistry (B2.1.2)

3.1.2.1.4 Steam Generator

Materials

The materials of construction for the steam generator subcomponents are:

- Nickel alloy
- Stainless steel
- Steel
- Steel with a stainless steel backing
- Steel with nickel alloy cladding
- Steel with stainless steel cladding

Environment

The steam generator subcomponents are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the steam generator 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 generator 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)
- 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 steel reactor vessel closure flange assembly components 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."

[3.1.1-002] – The evaluation of fatigue is a TLAA for nickel alloy steam generator components exposed to reactor coolant or secondary feedwater/steam in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.6, "Steam Generators."

[3.1.1-003] – The evaluation of fatigue is a TLAA for stainless steel reactor vessel internal components exposed to reactor coolant and neutron flux in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.5, "Reactor Vessel Internals Fatigue Analyses."

[3.1.1-004] – The SPS reactor vessels do not utilize support skirts. Therefore, this item is not applicable.

[3.1.1-005] – The evaluation of fatigue is a TLAA for steel pressurizer manway cover bolting and steel or stainless steel steam generator components in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.2, "Pressurizer," and Section 4.3.2.6, "Steam Generators."

[3.1.1-006] – Not applicable - BWR only.

[3.1.1-007] – Not applicable - BWR only.

[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 4.3.2.6, “Steam Generators.”

[3.1.1-009] – The evaluation of fatigue is a TLAA for stainless steel or steel (with stainless steel cladding or insert) reactor coolant pressure boundary components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.1, “Transient Cycle Projections for 80 Years,” and for stainless steel reactor coolant system primary loop piping, in Section 4.3.3 “ANSI B31.1 Allowable Stress Analyses,” 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 in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.4, “Reactor Vessel.”

[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 4.3.1, “Transient Cycle Projections for 80 Years.”

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).

[3.1.1-012] – 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. Information Notice 90-04, “Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators,” stated that volumetric examinations (UT) of the shell-to-transition-cone girth welds, required by Section XI of the ASME Code, may not be sufficient to differentiate isolated cracks from inherent geometric conditions. Following this notice, in addition to inspections required by ASME XI, a SPS steam generator transition cone girth weld was 100 percent MT inspected. No degradation indications were observed during these inspections. The continued implementation of the Water Chemistry (B2.1.2) program and the steam generator periodic inspections required by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will effectively manage loss of material for the steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam prior to loss of intended function.

(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.

[3.1.1-012] – Loss of material due to general, pitting, and crevice corrosion could result in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The steam generators were replaced at SPS in 1981 for Unit 1 and in 1980 for Unit 2. Only the lower shell assembly of the steam generator (Westinghouse Model 51F) was replaced, generating a cut in the middle of the transition cone and consequently creating a new transition cone closure weld. For this new transition cone closure weld, 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. The One-Time Inspection (B2.1.20) program will perform a magnetic particle test inspection of the continuous circumferential transition cone closure weld on each steam generator (minimum 25 percent examination coverage of each weld) prior to the subsequent period of extended operation. This one-time inspection along with the continued implementation of the Water Chemistry (B2.1.2) program and the steam generator periodic inspections required by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will effectively manage loss of material for the steel steam generator components prior to loss of intended function.

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.

[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."

[3.1.1-014] – Loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel beltline, shell, nozzle, and welds. The Reactor Vessel Material Surveillance (B2.1.19) program and the Neutron Fluence Monitoring (B3.2) program monitors 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.

[3.1.1-015] – 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."

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).

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" generic guidance for meeting the requirements of 10 CFR 54.21(c).

[3.1.1-018] – Reactor vessel underclad cracking is a TLAA as defined in 10 CFR 54.3 and is addressed in Section 4.7.7, Cracking Associated with Weld Deposited Cladding.

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).

[3.1.1-019] – Cracking due to stress corrosion cracking (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 program (B2.1.1) 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).

[3.1.1-020] – Cracking due to stress corrosion cracking (SCC) could occur in Class 1 PWR cast austenitic stainless steel reactor coolant system piping and piping components exposed to reactor coolant. SPS applicable components are the reactor coolant loop elbows. The cast austenitic stainless steel materials are consistent with the NUREG-0313 guidelines with regard to ferrite and carbon content as verified by certified material test reports. Mitigation and monitoring of cracking of the reactor coolant loop elbows 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 provides for periodic testing and inspections to detect cracking.

(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

[3.1.1-139] – Cracking due to SCC could occur in SS or nickel alloy reactor vessel flange leak detection lines of PWR light-water reactor facilities.

The reactor vessel flange leakoff line at SPS is made of stainless steel. A review of SPS operating experience has confirmed that cracking of the external surfaces of stainless steel components in indoor air has occurred. Cracking was found at SPS and was attributed to chloride induced transgranular stress corrosion cracking. Cracking has been identified on the external surfaces of stainless steel heat exchangers, piping, and welds in the residual heat removal system in the Containment buildings, as well as on safety injection instrument piping in the Unit 2 Safeguards building.

Cracking of a ¾ inch SPS Unit 2 residual heat removal balance line was identified in 2002. The source of chloride contamination at this location was not determined. Cracking was found at the Unit 1 residual heat removal heat exchangers in 2007 and at the Unit 2 residual heat removal heat exchangers in 2010.

The exact source of chloride contamination of the residual heat removal surfaces is unknown. Chloride contamination most likely originated from the insulation, although a review of the original insulation specification identified that requirements did exist when installing insulation on austenitic stainless steel to minimize the possibility of chlorides leaching from the insulation. In addition to repair of the damaged areas, the insulation was removed and the surfaces were cleaned and verified to be free of detectable chlorides.

Cracking of an uninsulated SPS Unit 2 low-head safety injection discharge flow element sensing line was identified in 2004. The cause was determined to be chloride induced stress corrosion cracking from the outside diameter. The apparent source of contamination was rainwater leakage into the valve pits housing the piping. Corrective actions included replacement of the affected piping and performing inspections of similar piping to identify any additional cracking (none was found).

Because cracking was found at both units, the potential for chloride contamination could not be discounted. The potential for cracking of stainless steel in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

Cracking of the stainless steel reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.

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 SPS 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.

[3.1.1-028] [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] [3.1.1-119] – Electric Power Research Institute (EPRI) Topical Report (TR)-1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-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. The methodology in MRP-227-A was approved by the NRC in a safety evaluation dated December 16, 2011, 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 approved MRP-227-A guidelines are based on an analysis of the reactor vessel internals that considers the operating conditions up to a 60 year operating period. 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-A Gap Analysis for PWR Vessel Internals Aging Management (Appendix C) provides a basis for identifying and justifying changes to the MRP-227-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 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 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).

[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 nozzles or control rod drive mechanism nozzle head adapter tubes.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program includes inspection of the control rod drive head penetration nozzles for loss of material due to wear.

(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 described 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.

[3.1.1-117] – Loss of material due to wear can occur in the stainless steel thermal sleeves of PWR control rod drive head penetration nozzles due to the interaction between the nozzle and the thermal sleeve (e.g., where the thermal sleeve exits from the head penetration nozzle inside the reactor vessel).

The PWR Vessel Internals (B2.1.7) program includes inspection of the control rod drive head penetration nozzle thermal sleeves for loss of material due to wear.

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

[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.

SPS steam generator (Westinghouse Model 51) divider plates and associated welds are fabricated of Alloy 600 materials. The analysis performed by the industry (EPRI 3002002850) evaluated divider plate cracking for the Westinghouse Model 51 steam generator, which were determined to be the most limiting steam generator model. Since the analysis is applicable and bounding for the SPS steam generators, a plant-specific AMP is not necessary.

Cracking of the SPS 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.

[3.1.1-025] – Cracking due to PWSCC could occur in steam generator nickel alloy tube-to-tubesheet welds exposed to reactor coolant. For SPS, the H* alternate repair criteria have been permanently approved for both the hot-leg and cold-leg side of the steam generators; therefore the welds are no longer part of the reactor coolant pressure boundary and a plant-specific AMP is not necessary.

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.

[3.1.1-105] – Loss of material of steel with an external environment of concrete is not applicable to components in the reactor coolant system. The steel neutron shield tanks are encased in concrete that conforms to ACI 318, "Building Code Requirements for Structural Concrete." Review of SPS operating experience did not identify degradation of concrete around embedded components that could lead to penetration of water, and the tanks are not potentially exposed to groundwater. No other piping components in the reactor coolant system are exposed to concrete.

[3.1.1-115] – There are no in-scope stainless steel piping, 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.

Loss of material due to pitting and crevice corrosion is an aging effect requiring management for stainless steel and nickel alloy components exposed to air in the Reactor Vessel, Internals, and Reactor Coolant System for SPS.

A review of SPS operating experience confirmed that loss of material of the external surfaces of stainless steel components in indoor air has occurred. Examples of externally initiated stress corrosion cracking are described in Section 3.1.2.2.6.3. Pitting was noted in some of the same general areas as cracking in the residual heat removal and safety injection systems.

Pitting and crevice corrosion of stainless steel and nickel alloy in air is supported by the presence of the same contaminants that support stress corrosion cracking. Since pitting was identified in some of the same general locations as cracking in the safety injection and residual heat removal systems, the potential for chloride contamination could not be discounted, and because leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for loss of material due to pitting and crevice corrosion of stainless steel and nickel alloy in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.1.1-136] – Loss of material of stainless steel or nickel alloy components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.

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.

Intentionally Blank

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 secondary feedwater/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)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel reactor vessel internal components exposed to reactor coolant and neutron flux is a TLAA. See further evaluation in Section 3.1.2.2.1.
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. SPS has no in-scope steel 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. See further evaluation in Section 3.1.2.2.1.
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.
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 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
3.1.1-010	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 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. The One-Time Inspection (B2.1.20) program will verify the effectiveness of the Water Chemistry (B2.1.2) program to manage loss of material for the new transition cone closure weld. See further evaluation in Section 3.1.2.2.2.1 and 3.1.2.2.2.2.
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.

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
3.1.1-014	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. 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. SPS Units 1 and 2 utilize Westinghouse reactors. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.1.2.2.3.3.
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.
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)	Consistent with NUREG-2191. Crack growth due to cyclic loading of reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process exposed to reactor coolant is a TLAA. See further evaluation in Section 3.1.2.2.5.

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
3.1.1-019	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 with exceptions. 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. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. 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 with exceptions. Cracking of cast austenitic stainless steel Class 1 piping, piping components 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. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. 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. SPS has 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. See further evaluation in Section 3.1.2.2.8.

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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. See further evaluation in Section 3.1.2.2.11.1 and 3.1.2.2.11.2.
3.1.1-028	Existing Programs components: Stainless steel, nickel alloy Westinghouse control rod guide tube support pins, and Combustion Engineering thermal shield positioning pins; Zircaloy-4 Combustion Engineering incore instrumentation thimble tubes exposed to reactor coolant and neutron flux	Loss of material due to wear; cracking due to SCC, irradiation-assisted SCC, 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 for loss of material with a different program credited. The Flux Thimble Tube Inspection (B2.1.24) program will manage loss of material for nickel alloy flux thimble tubes. See further evaluation in Section 3.1.2.2.9.
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, irradiation-assisted SCC	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.

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
3.1.1-031	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.
3.1.1-032	Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure (not already referenced as ASME Section XI Examination Category B-N-3 core support structure components in MRP-227-A), exposed to reactor coolant and neutron flux	Cracking, loss of material due to wear	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable. The associated NUREG-2191 aging items are not used.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. 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. SPS has 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.

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
3.1.1-035	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.
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	Consistent with NUREG-2191.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Code Class 1 Small-Bore Piping (B2.1.22) and Water Chemistry (B2.1.2) program implementation. 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.

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
3.1.1-040	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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, irradiation-assisted SCC	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.
3.1.1-042	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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.

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
3.1.1-044	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) 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
3.1.1-047	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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.
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. Additionally, thermal embrittlement of cast austenitic stainless steel reactor coolant pump casings is a TLAA, evaluated in Section 4.7.6, Reactor Coolant Pump Code Case N-481.

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
3.1.1-051a	Stainless steel, nickel alloy Babcock & Wilcox reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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, irradiation-assisted SCC, 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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, irradiation-assisted SCC, 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. SPS Units 1 and 2 utilize Westinghouse reactors. The associated NUREG-2191 aging items are not used.
3.1.1-052b	Stainless steel, nickel alloy Combustion Engineering reactor internal Expansion components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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, irradiation-assisted SCC, 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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
3.1.1-053a	Stainless steel, nickel alloy Westinghouse reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. The core barrel (lower flange weld) and core barrel (upper girth weld) align to this item but are listed as Expansion components in the Appendix C Gap Analysis. 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, irradiation-assisted SCC, 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. The brackets, clamps, terminal blocks and conduit straps located on the periphery align to this item, and are expected to be elevated to a Primary Inspection component, as described in the Appendix C Gap Analysis. The upper internals (upper core plate) aligns to this item, and is listed as a Primary Inspection component in the Appendix C Gap Analysis. See further evaluation in Section 3.1.2.2.9.
3.1.1-053c	Stainless steel, nickel alloy Westinghouse reactor internal Existing Programs components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. Clevis insert bolts and dowels align to this item, but are listed as Primary Inspection components in the Appendix C Gap Analysis. See further evaluation in Section 3.1.2.2.9.
3.1.1-054	Stainless steel 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	Not applicable. Loss of material due to wear is addressed in row 3.1.1-028. The associated NUREG-2192 aging item is 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
3.1.1-055a	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. SPS Units 1 and 2 utilize Westinghouse reactors. 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. SPS Units 1 and 2 utilize Westinghouse reactors. The associated NUREG-2191 aging items are not used.
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.

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
3.1.1-056a	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. SPS Units 1 and 2 utilize Westinghouse reactors. 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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. SPS Units 1 and 2 utilize Westinghouse reactors. 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. The core barrel (lower flange and lower axial welds) and the lower support (column body) also align to this item, but are listed as Expansion components in the Appendix C Gap Analysis. The lower internals (fuel alignment pin) also aligns to this item, but is listed as an Existing component in the Appendix C Gap Analysis. 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. The control rod guide tube (guide tube support pin nut) (Unit 1 only) aligns to this item, but is treated as an Existing component in the Appendix C Gap Analysis. 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) or nickel alloy 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. Clevis insert bolts and dowels align to this item, but are listed as Primary Inspection components in the Appendix C Gap Analysis. Bottom mounted instrumentation (column body) aligns to this item, but is listed as Expansion component in the Appendix C Gap Analysis. Core barrel (core barrel flange) aligns to this item, but is listed as both Primary Inspection and Existing component in the Appendix C Gap Analysis. 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. SPS has no in-scope high-strength steel, stainless steel closure bolting; 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.
3.1.1-063	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. SPS has 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	Not applicable. SPS has no in-scope steel or 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.
3.1.1-067	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. SPS has no steel steam generator tube support plates. 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Reactor Vessel, Internals, And Reactor Coolant System, the nickel alloy steam generator blowdown system piping internal to the steam generator (in the Steam and Power Conversion System (blowdown)) is aligned to this row.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) 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
3.1.1-073	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. SPS has 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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. SPS has 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.

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
3.1.1-077	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. In addition to Reactor Vessel, Internals, And Reactor Coolant System, the nickel alloy steam generator blowdown system piping internal to the steam generator in the Steam and Power Conversion System (blowdown) is aligned to this row. Wear of steam generator tubes at tube support plates is a TLAA, evaluated in Section 4.7.9, Steam Generator Tube Wear Evaluation.
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. SPS steam generators are recirculating and 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. SPS has 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.

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
3.1.1-081	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. SPS pressurizer spray heads are not within the scope of subsequent license renewal. 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	Not applicable. SPS pressurizer spray heads are not within the scope of subsequent license renewal. The associated NUREG-2191 aging items are not used.
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 steel steam generator shell assembly exposed to secondary feedwater or steam is addressed in row 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. SPS has 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.

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
3.1.1-087	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	Not applicable. Loss of material for reactor vessel internal components exposed to reactor coolant and neutron flux is addressed in rows 3.1.1-028, 3.1.1-059a, 3.1.1-059b, 3.1.1-059c, and 3.1.1-119. The associated NUREG-2191 aging items are not used.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Reactor Vessel, Internals, And Reactor Coolant System, components in the Auxiliary Systems (chemical and volume control) are aligned to this row.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated water Systems (B2.1.12) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated water Systems (B2.1.12) program implementation.
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.

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
3.1.1-092	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.
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	Consistent with NUREG-2191.
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, irradiation-assisted SCC	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)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.15.
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 applicable aging effect 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 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 (stainless steel, nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, 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 in rows 3.1.1-020, 3.1.1-033, 3.3.1-037, 3.1.1-039, 3.1.1-042, 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. SPS has 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. See further evaluation in Section 3.1.2.2.15.

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)	Consistent with NUREG-2191. Loss of material of nickel alloy control rod drive components exposed to reactor coolant is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program. 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. Loss of material of control rod drive penetration nozzle thermal sleeves is managed by the PWR Vessel Internals (B2.1.7) program, as addressed in row 3.1.1-059a. 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 exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, cyclic loading, fatigue	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. Cracking of stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux is addressed in rows 3.1.1-053a, 3.1.1-053b and 3.1.1-053c. The associated NUREG-2191 aging items are not used.
3.1.1-119	Stainless steel, nickel alloy PWR reactor vessel internal components 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	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191 for loss of fracture toughness and changes in dimensions. Loss of fracture toughness and changes in dimension for nickel alloy flux thimble tubes is managed by the PWR Vessel Internals (B2.1.7) program. Loss of preload is not applicable to flux thimble tubes, and loss of material for the flux thimble tubes is addressed in row 3.1.1-028. Flux thimble tubes are Existing program components. 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
3.1.1-120	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.
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	Not applicable. Flow induced vibration at the tubesheet caused by turbulence, fluidelastic excitation, and vortex shedding has been evaluated for the SPS steam generators. These analyses have revealed that at the maximum alternating bending stress in the tube, the code allowable number of cycles is infinite and the fatigue factor is zero. Cracking due to high cycle fatigue does not require aging management, 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
3.1.1-127	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 with exceptions, and with a different program for some components. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. 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 nozzles exposed to reactor coolant.
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.
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.

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
3.1.1-134	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	Consistent with NUREG-2191.
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 and nickel alloy components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. See further evaluation in Section 3.1.2.2.16.
3.1.1-137	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
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 stainless steel reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) 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 and ring (and cladding)	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-55	3.1.1-047	C
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	D
				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	B
Bottom mounted instrumentation guide tube	PB	Stainless steel	(E) Air – Indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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-154	3.1.1-019	E, 2
					Water Chemistry (B2.1.2)	IV.A2.RP-154	3.1.1-019	E, 2
				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	B
Closure head dome and flange (and cladding)	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	D
				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	B

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 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
Control rod drive mechanism (head adapter plug)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Control rod drive mechanism (housing flange)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B

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 (housing tube)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.R-413	3.1.1-116	E, 4
Control rod drive mechanism (latch housing)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Control rod drive mechanism (rod travel housing)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B

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
Core support lug	SS	Nickel alloy	(I) 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, 1
					Water Chemistry (B2.1.2)	IV.A2.RP-57	3.1.1-040a	B
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	D
Head vent pipe	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.R-90	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.R-90	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.R-90	3.1.1-045	B
				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	B
Instrumentation port assembly	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	C
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	D
				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	B

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
Instrumentation tube	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Instrumentation tube safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	C
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	D
				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	B
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

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 (and cladding)	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	TLAA	None	None	H, 3
					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	D
				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	A
					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	B
Primary nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	B
				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	B
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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	D
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	B
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 (and cladding)	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	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	D
				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	B
Vessel flange leakage monitor line	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.A2.R-74b	3.1.1-139	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	D
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	C
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	D

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 and cladding)	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	Crack growth	TLAA	IV.A2.R-85	3.1.1-018	A
				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	D
				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	A
					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 core support lug is an integral part of the reactor vessel and is also known as the clevis. The associated clevis insert bolting, dowel, and wear surface, and the radial support key and wear surface are addressed in the reactor vessel internals aging management review.
2. 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).
3. Crack growth is a TLAA, evaluated in Section 4.7.8.
4. The plant-specific aging management program used to manage loss of material due to wear of the control rod drive mechanism (housing tube) is the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) 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 (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	B
				Loss of material; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-285	3.1.1-059c	A
Alignment and interfacing (clevis insert dowel)	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
Alignment and interfacing (clevis insert wear surface)	SS	Stellite	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	None	None	F, 5
				Loss of material	PWR Vessel Internals (B2.1.7)	None	None	F, 5
Alignment and interfacing (internals hold-down spring)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-271	3.1.1-053a	C
					Water Chemistry (B2.1.2)	IV.B2.RP-271	3.1.1-053a	D
				Loss of preload; changes in dimensions; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-300	3.1.1-059a	A, 1
Alignment and interfacing (radial support key wear surface)	SS	Stellite	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	None	None	F, 5
Alignment and interfacing (thermal sleeve)	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
Alignment and interfacing (upper core plate alignment pin wear surface)	SS	Stellite	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	None	None	F, 5
Alignment and interfacing (upper core plate alignment pin)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-355	3.1.1-053c	C
					Water Chemistry (B2.1.2)	IV.B2.RP-355	3.1.1-053c	D
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-299	3.1.1-059c	A

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 former (baffle edge bolt)	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	B
				Loss of fracture toughness; changes in dimensions; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-354	3.1.1-059a	A
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	C
Baffle former (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	B
				Loss of fracture toughness; changes in dimensions; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-354	3.1.1-059a	A
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	C
Baffle former (baffle plate)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	A
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270a	3.1.1-053a	A
						IV.B2.RP-387	3.1.1-053a	C
					Water Chemistry (B2.1.2)	IV.B2.RP-270a	3.1.1-053a	B
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388	3.1.1-059a	C
Baffle former (corner bolt)	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	B
				Loss of fracture toughness; changes in dimensions; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-354	3.1.1-059a	C
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	C
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	B
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-299	3.1.1-059c	C

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
Bottom mounted instrumentation (flux thimble tube)	SS	Nickel alloy	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-355	3.1.1-053c	C
					Water Chemistry (B2.1.2)	IV.B2.RP-355	3.1.1-053c	D
				Loss of fracture toughness; changes in dimensions; loss of preload; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.R-424	3.1.1-119	E, 3
				Loss of material	Flux Thimble Tube Inspection (B2.1.24)	IV.B2.RP-356	3.1.1-028	E, 2
Control rod guide tube (guide plate)	SS	Cast austenitic stainless steel	(E) Reactor coolant >250°C (>482°F) and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-298	3.1.1-053a	C
					Water Chemistry (B2.1.2)	IV.B2.RP-298	3.1.1-053a	D
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	C
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	A
		Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-298	3.1.1-053a	C
					Water Chemistry (B2.1.2)	IV.B2.RP-298	3.1.1-053a	D
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	A
Control rod guide tube (guide tube support pin nut) (Unit 1 only)	SS	Nickel alloy	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-355	3.1.1-053c	C,10
				Loss of fracture toughness; loss of preload	PWR Vessel Internals (B2.1.7)	IV>B2.RP-287	3.1.1-059b	C,10, 11
Control rod guide tube (guide tube support pin) (Unit 1 only)	SS	Nickel alloy	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-355	3.1.1-053c	A,10
					Water Chemistry (B2.1.2)	IV.B2.RP-355	3.1.1-053c	B,10
				Loss of fracture toughness; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-287	3.1.1-059b	C,10
				Loss of material; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-285	3.1.1-059c	C,10
Control rod guide tube (lower flange)	SS	Cast austenitic stainless steel	(E) Reactor coolant >250°C (>482°F) and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-298	3.1.1-053a	C, 8
					Water Chemistry (B2.1.2)	IV.B2.RP-298	3.1.1-053a	D, 8
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	C, 8
		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	B
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	A

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 (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	B
				Loss of fracture toughness; changes in dimensions; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-274	3.1.1-059b	A
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-345	3.1.1-059c	A
Core barrel (core barrel flange)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-280	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-280	3.1.1-053a	B
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-345	3.1.1-059c	A
Core barrel (core barrel outlet nozzle)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-278	3.1.1-053b	A, 9
					Water Chemistry (B2.1.2)	IV.B2.RP-278	3.1.1-053b	B, 9
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-290b	3.1.1-059b	C
Core barrel (lower axial weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	C
				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	B
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388a	3.1.1-059b	A
Core barrel (lower flange weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	C
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-280	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-280	3.1.1-053a	B
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	C
Core barrel (lower girth weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	C
				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	B
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388	3.1.1-059a	A
Core barrel (upper 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	B
Core barrel (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	B

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 (upper 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	B
Lower internals (fuel alignment pin)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	C
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-289	3.1.1-053c	C
					Water Chemistry (B2.1.2)	IV.B2.RP-289	3.1.1-053c	D
				Loss of fracture toughness; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-288	3.1.1-059c	C
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	D
				Cumulative fatigue damage	TLAA	IV.B2.RP-303	3.1.1-003	A, 4
				Loss of fracture toughness; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-288	3.1.1-059c	A
Lower support (column body)	SS	Cast austenitic stainless steel	(E) Reactor coolant >250°C (>482°F) and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	C
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-291	3.1.1-053b	A
						IV.B2.RP-291a	3.1.1-053b	C
					Water Chemistry (B2.1.2)	IV.B2.RP-291	3.1.1-053b	B
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-290	3.1.1-059b	A
Lower support (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	B
				Loss of fracture toughness; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-287	3.1.1-059b	A
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-290b	3.1.1-059b	C
Lower support (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
No additional measures components	FD;SS	Nickel alloy	(E) Reactor coolant and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 6
		Stainless steel	(E) Reactor coolant and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 6

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
Thermal shield (flexure)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-302	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-302	3.1.1-053a	B
Upper internals (fuel alignment pin)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-289	3.1.1-053c	C
					Water Chemistry (B2.1.2)	IV.B2.RP-289	3.1.1-053c	D
				Loss of fracture toughness; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-288	3.1.1-059c	C
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	B
				Cumulative fatigue damage	TLAA	IV.B2.RP-303	3.1.1-003	A, 4
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-295	3.1.1-059b	C
Upper internals (upper support ring)	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	B

Table 3.1.2-2 Plant-Specific Notes:

1. Changes in dimensions is not applicable to the internals hold-down spring, per MRP-191 Rev. 2.
2. The Flux Thimble Tube Inspection (B2.1.24) program will manage loss of material for nickel alloy flux thimble tubes.
3. The PWR Vessel Internals (B2.1.7) program will manage loss of fracture toughness and changes in dimension for nickel alloy flux thimble tubes. Loss of preload is not applicable to flux thimble tubes, and loss of material is addressed by NUREG-2191 item IV.B2.RP-356. Flux thimble tubes are existing program components.
4. Fatigue analyses were performed for the upper and lower core plates. See Section 4.3.5, Reactor Vessel Internals Fatigue Analyses.
5. Wear surfaces for the upper core plate alignment pins, clevis inserts, and radial support keys are Stellite. Aging effects identified in the Appendix C Gap Analysis for these components are managed by the PWR Vessel Internals (B2.1.7) program.
6. No additional measures components are itemized in the Appendix C Gap Analysis.
7. Not used.
8. The NUREG-2191 Item is for lower flange welds (accessible), which are stainless steel; the lower flange is cast austenitic stainless steel.
9. This item includes the associated welds, which are also stainless steel.
10. The Unit 2 control rod guide tube (guide tube support pin and support pin nut) are “No additional measures” components, as identified in the Appendix C Gap Analysis.
11. Loss of preload is not an applicable aging effect for the control rod guide tube (guide tube support pin nut), as identified in the Appendix C Gap Analysis.

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;SI	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.D1.RP-46	3.1.1-067	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
Flexible hose	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Heat exchanger (reactor coolant pump motor lower bearing oil cooler - coiled tube inside the reservoir)	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	D
			(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 (reactor coolant pump motor lower bearing oil cooler - coiled tube outside the reservoir)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	IV.E.R-453	3.1.1-137	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	D
Heat exchanger (reactor coolant pump motor stator cooler - fin and tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	IV.E.R-453	3.1.1-137	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	D

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 (reactor coolant pump motor upper bearing oil cooler - channel head)	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	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-221	3.1.1-089	D
Heat exchanger (reactor coolant pump motor upper bearing 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	A
			(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 (reactor coolant pump motor upper bearing oil cooler - tubes)	PB	Copper alloy (>15% Zn)	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	D
					Selective Leaching (B2.1.21)	IV.C2.RP-12	3.1.1-093	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 (reactor coolant pump motor upper bearing oil cooler - tubesheet)	PB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-221	3.1.1-089	D
			(E) 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
Hydraulic isolator	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B

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
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Piping, piping components	LB;PB;SI	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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-05	3.1.1-020	E, 2
					Water Chemistry (B2.1.2)	IV.C2.R-05	3.1.1-020	B
					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	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	A
			(I) Gas	None	None	IV.E.RP-07	3.1.1-107	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	LB;PB;SI	Stainless steel	(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	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-56	3.1.1-035	A
					ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A, 3
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	B
				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	B
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	D
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-98	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.A-98	3.3.1-125	D
		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
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	V.A.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	B

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 (heater well and heater sheath)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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-217	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-217	3.1.1-033	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	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	B
Pressurizer (instrument nozzles)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Pressurizer (lower head and cladding)	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	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	B
				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	B

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 (manway - includes pad and cladding)	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	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	B
				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	B
Pressurizer (manway cover and insert)	PB	Steel with stainless steel insert	(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	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	B
				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	B
Pressurizer (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.C2.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.C2.RP-167	3.1.1-049	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 (relief nozzle and cladding)	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	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	B
				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	B
Pressurizer (relief nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Pressurizer (safety nozzle and cladding)	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	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	B
				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	B

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 (safety nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Pressurizer (sample line nozzle)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Pressurizer (seismic support lugs)	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	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 (shell and cladding)	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	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	B
				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	B
Pressurizer (spray nozzle and cladding)	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	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	B
				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	B
Pressurizer (spray nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Pressurizer (spray nozzle thermal sleeve)	LTC	Stainless steel	(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	B
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	B

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 (support skirt and flange)	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	A
Pressurizer (surge nozzle and cladding)	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	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	B
				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	B
Pressurizer (surge nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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	B
Pressurizer (surge nozzle thermal sleeve)	LTC	Stainless steel	(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	B
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	B

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 (upper head and cladding)	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	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	B
				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	B
Pump casing (reactor coolant)	PB	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				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
					TLAA	IV.C2.R-52	3.1.1-050	E, 1
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	B
Tank (neutron shield)	PB;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	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-221	3.1.1-089	B
			(E) Concrete	None	None	IV.E.RP-353	3.1.1-105	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 (pressurizer relief)	LB	Steel with internal coating	(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	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F3.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F3.A-414	3.3.1-139	A
Thermal insulation	TI	Fiberglass	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-450	3.1.1-134	A
Valve body	LB;PB;SI	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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	B
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of fracture toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-08	3.1.1-038	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	B

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
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	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-09	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-09	3.1.1-033	B
				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	D
			(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	B
			(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	B
		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	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A

Table 3.1.2-3 Plant-Specific Notes:

1. Fatigue crack growth of the reactor coolant pump casing is a plant specific TLAA evaluated in Section 4.7.6, Reactor Coolant Pump Code Case N-481.
2. The plant-specific aging management program used to manage cracking of ASME class 1 cast austenetic stainless steel piping is the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program.
3. Includes consideration of sensitized stainless steel.

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - 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	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	B
				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	B
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Channel head (and cladding)	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	C
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	D
				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	B
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	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	C
Feedwater inlet nozzle	PB	Steel	(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	D
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A
Feedwater inlet nozzle thermal sleeve	LTC	Stainless steel	(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	D
				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	D
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Feedwater inlet ring	FD	Stainless steel	(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	D
				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	D
					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	D
				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	D
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
Feedwater inlet ring J nozzle	FD	Stainless steel	(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	D
				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	D
					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	D
				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	D
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
Moisture separator assembly	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	D
				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	B
			(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	D
				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	B

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - 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 nozzle and outlet nozzle (and cladding)	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	B
				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, 2
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	B
Primary inlet nozzle safe end and outlet nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	C
			(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	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
Primary manway (includes pad and cladding)	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	B
				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	B

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - 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 and insert	PB	Steel with a stainless steel backing	(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	B
				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	B
Primary manway cover bolt	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 closure cover	PB	Steel	(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	D
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-31	3.1.1-044	A
Secondary closure cover bolt	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 Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Secondary manway (includes pad)	PB	Steel	(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	D
Secondary side shell (head, upper shell, lower shell, transition cone, girth weld)	PB	Steel	(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	A
					One-Time Inspection (B2.1.20)	IV.D1.RP-368	3.1.1-012	E, 3
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	B
Secondary side shell penetration	PB	Steel	(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	D
Stay rod	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	B
				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	B
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Steam flow limiter	RF	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	D
				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	D

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steam outlet nozzle	PB	Steel	(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	D
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A
Support pad	SS	Steel	(E) Air with borated water leakage	Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	A
				Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Tube bundle wrapper	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	B
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	B
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	A
Tube support plate	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	B
				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	B
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Tubesheet (and cladding)	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	B
			(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	D

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
U-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	B
				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	B
				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, 1
				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	B

Table 3.1.2-4 Plant-Specific Notes:

1. Wear of steam generator tubes at tube support plates is a plant-specific TLAA, evaluated in Section 4.7.8, Steam Generator Tube High Cycle Fatigue Evaluation.
2. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used to manage loss of material for the primary inlet and outlet nozzles exposed to reactor coolant.
3. The One-Time Inspection (B2.1.20) program will verify the effectiveness of the Water Chemistry (B2.1.2) program to manage loss of material for the new transition cone closure weld.

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.

Intentionally Blank

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.

- Containment Spray (Section 2.3.2.1)
- Recirculation Spray (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 - Containment Spray - Aging Management Evaluation
- Table 3.2.2-2, Engineering Safety Features - Recirculation Spray - 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 Containment Spray

Materials

The materials of construction for the containment spray system component types are:

- Copper alloy (>15 percent Zn)
- Stainless steel
- Steel

Environment

The containment spray system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Condensation
- Soil
- Treated borated water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the containment spray system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the containment spray 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)
- Buried and Underground Piping and Tanks (B2.1.27)
- 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 Recirculation Spray

Materials

The materials of construction for the recirculation spray system component types are:

- Copper alloy
- Copper alloy (>15 percent Zn)
- Stainless steel
- Steel
- Titanium (ASTM Grade 2)

Environment

The recirculation spray system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Lubricating oil
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the recirculation spray 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 recirculation spray 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)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- 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)

3.2.2.1.3 Residual Heat Removal

Materials

The materials of construction for the residual heat removal system component types are:

- Copper alloy
- Stainless steel
- Steel

Environment

The residual heat removal system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Concrete
- Gas
- Soil
- 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

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)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- 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:

- Copper alloy
- 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 – outdoor
- Air with borated water leakage
- Concrete
- Gas
- Soil
- 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 safety injection system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer

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 (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- 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 4.3.3, Metal Fatigue - ANSI B31.1.

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.

Loss of material due to pitting and crevice corrosion is an aging effect requiring management for stainless steel components exposed to air in the Engineered Safety Features systems for SPS.

A review of SPS operating experience confirmed that loss of material of the external surfaces of stainless steel components in indoor air has occurred. Examples of externally initiated stress corrosion cracking are described in Section 3.2.2.2.4. Pitting was noted in some of the same general areas as cracking in the residual heat removal and safety injection systems.

Pitting and crevice corrosion of stainless steel in air-indoor uncontrolled or air-outdoor is supported by the presence of the same contaminants that support stress corrosion cracking. Since pitting was identified in some of the same general locations as cracking in the safety injection and residual heat removal systems, the potential for chloride contamination could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for loss of material due to pitting and crevice corrosion of stainless steel in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.2.1-004] – Loss of material of stainless steel components exposed to air-indoor uncontrolled or air-outdoor is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. The internal surfaces of some components in the containment spray, recirculation spray, and safety injection system are aligned to this item, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.2.1-048] – Loss of material of stainless steel components exposed to air-indoor uncontrolled is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

[3.2.1-099] – Loss of material of stainless steel tanks exposed to air-indoor uncontrolled is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) 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 air or condensation is managed 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 condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.

[3.2.1-112] – SPS has no in-scope stainless steel or nickel alloy underground piping, piping components or tanks in the Engineered Safety Features systems.

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.

Cracking due to stress corrosion cracking is an aging effect requiring management for stainless steel components exposed to air in the Engineered Safety Features systems for SPS.

Operating experience has confirmed that cracking of the external surfaces of stainless steel components in indoor air has occurred. Cracking was found at SPS and was attributed to chloride induced transgranular stress corrosion cracking. Cracking has been identified on the external surfaces of stainless steel heat exchangers, piping, and welds in the residual heat removal system in the Containment buildings at SPS, as well as on safety injection instrument piping in the SPS Unit 2 Safeguards building.

Cracking of a SPS Unit 2 small bore residual heat removal balance line was identified in 2002. The source of chloride contamination at this location was not determined. Cracking was found at the SPS Unit 1 residual heat removal heat exchangers in 2007 and at the SPS Unit 2 residual heat removal heat exchangers in 2010.

The exact source of chloride contamination of the residual heat removal surfaces is unknown. Chloride contamination most likely originated from the insulation, although a review of the original insulation specification identified that requirements did exist when installing insulation on austenitic stainless steel to minimize the possibility of chlorides leaching from the insulation. In addition to repair of the damaged areas, the insulation was removed and the surfaces were cleaned and verified to be free of detectable chlorides.

Cracking of an uninsulated SPS Unit 2 low-head safety injection discharge flow element sensing line was identified in 2004. The cause was determined to be chloride induced stress corrosion cracking from the outside diameter. The apparent source of contamination was rainwater leakage into the valve pits housing the piping. Corrective actions included replacement of the affected piping and performing inspections of similar piping to identify any additional cracking (none was found).

Because cracking was found at SPS, the potential for chloride contamination could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for cracking of stainless steel in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.2.1-007] – Cracking of stainless steel components exposed to air-indoor uncontrolled or air-outdoor is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the containment spray, recirculation spray, and safety injection systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. Additionally, cracking of sensitized stainless steel exposed to air-indoor uncontrolled in the containment spray and recirculation spray systems is managed by augmented inspections within the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program.

[3.2.1-080] – SPS has no in-scope stainless steel underground piping, piping components or tanks in the Engineered Safety Features systems.

[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 air or condensation is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-108] – Cracking of stainless steel components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) 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.

[3.2.1-066] – Loss of material due to recurring internal corrosion is not an aging effect requiring management for metallic piping, piping components or tanks exposed to raw water or waste water in the Engineered Safety Features systems for SPS.

A review of SPS 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

Cracking due to stress corrosion cracking in aluminum components is not an aging effect requiring management for the Engineered Safety Features systems at SPS.

[3.2.1-100] – SPS has 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.

[3.2.1-101] – SPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation (external) in the Engineered Safety Features systems.

[3.2.1-102] – SPS has 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.

[3.2.1-109] – SPS has no in-scope insulated aluminum piping, piping components or tanks exposed to air or condensation in the Engineered Safety Features systems.

[3.2.1-110] – SPS has no in-scope aluminum underground piping, piping components or tanks in the Engineered Safety Features systems.

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.

Loss of material due to crevice or pitting corrosion, and cracking due to SCC can occur in stainless steel components exposed to concrete in the Engineered Safety Features at SPS.

[3.2.1-055] – SPS has no in-scope steel piping, piping components exposed to concrete in the Engineered Safety Features systems.

[3.2.1-091] – The concrete exposed stainless steel piping aligned to this item is embedded within interior concrete at the containment sump and is not potentially exposed to groundwater. There are no aging effects identified that require aging management.

Loss of material and cracking can occur for stainless steel piping components with an external environment of concrete that are potentially exposed to groundwater. Embedded piping that exits concrete into soil is potentially exposed to groundwater. Loss of material and cracking for stainless steel components with an external environment of concrete that exit the concrete into soil is managed by the Buried and Underground Piping and Tanks (B2.1.27) program as identified in items [3.2.1-053] and [3.3.1-078]

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.

Loss of material due to pitting and crevice corrosion in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment is not an aging effect requiring management for the Engineered Safety Features systems at SPS.

[3.2.1-042] – SPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation (external) in the Engineered Safety Features systems.

[3.2.1-056] – SPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation (internal) in the Engineered Safety Features systems.

[3.2.1-105] – SPS has 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.

[3.2.1-111] – SPS has no in-scope aluminum underground piping, piping components or tanks in the Engineered Safety Features systems.

[3.2.1-119] – SPS has no in-scope insulated aluminum piping, piping components or tanks exposed to air or condensation in the Engineered Safety Features systems.

[3.2.1-121] – SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Engineered Safety Features systems.

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 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 is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. The internal surfaces of some components in the containment spray, recirculation spray, and safety injection systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. 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 system charging pump miniflow orifice) 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 with a different program for some components. Cracking of stainless steel components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the containment spray, recirculation spray, and safety injection systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant, reactor vessel and steam generator) are aligned to this item. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will manage cracking of sensitized stainless steel. 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	Consistent with NUREG-2191.
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.

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
3.2.1-010	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. SPS has 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.
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. SPS has no in-scope steel piping, piping components exposed to steam or treated water in the Engineered Safety Features systems. 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. SPS has no in-scope high-strength steel closure bolting exposed to air, soil, or underground 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. No Engineered Safety Features components are aligned to this item. 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
3.2.1-017	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. SPS has 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.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) and Auxiliary Systems (boron recovery, water treatment and gaseous waste) 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. SPS has no in-scope steel heat exchanger components, piping, piping 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
3.2.1-024	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. SPS has 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. SPS has 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.
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. SPS has 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. SPS has 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. SPS has no in-scope steel piping, piping components exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging item is 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.

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
3.2.1-031	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.
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. SPS has 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.
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. SPS has 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. SPS has no in-scope gray cast iron motor cooler 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. SPS has 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.

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
3.2.1-037	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. SPS has 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. SPS has 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.
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)	Not applicable. SPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation (external) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. SPS has 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 Auxiliary Systems (buildings and structures, gaseous waste and vents aerated) 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
3.2.1-045	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. SPS has 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. SPS has 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. SPS has 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.
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 components exposed to air is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) 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	Consistent with NUREG-2191.
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 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
3.2.1-051	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	Not applicable. SPS has no in-scope steel, copper alloy or stainless steel heat exchanger tubes exposed to lubricating oil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope steel piping, piping components exposed to soil, concrete or underground in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
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)	Not applicable. SPS has no in-scope steel piping, piping components exposed to concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.2.2.2.9.

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
3.2.1-056	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. SPS has 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. See further evaluation in Section 3.2.2.2.10.
3.2.1-057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
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. SPS has no in-scope copper alloy or 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.
3.2.1-059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Not applicable. SPS has no in-scope galvanized steel ducting, ducting components or 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	Not applicable. SPS has no in-scope glass piping elements exposed to air, underground, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas or 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
3.2.1-062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. SPS has 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	Not applicable. Wall thinning due to erosion is not an aging effect requiring management for metallic 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.
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. Recurring internal corrosion has not been identified by a search of SPS operating experience for 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. See further evaluation in Section 3.2.2.2.7.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.

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
3.2.1-068	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	Not applicable. SPS has no in-scope steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope insulated steel piping, piping components or tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air-outdoor or condensation in the Engineered Safety Features systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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. SPS has 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.

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
3.2.1-072	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	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. SPS has no in-scope piping, piping components, heat exchangers or tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water or treated borated water 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	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. SPS has 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 or lubricating oil 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. SPS has 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.
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	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
3.2.1-078	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	Consistent with NUREG-2191.
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)	Not applicable. SPS has no in-scope stainless steel underground piping, piping components or tanks in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used. 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	Consistent with NUREG-2191.
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	Not applicable. SPS has no in-scope non-metallic thermal insulation exposed to air or condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. 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.

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
3.2.1-091	Stainless 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.
3.2.1-096	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. SPS has 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. SPS has 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)	Consistent with NUREG-2191. Loss of material of stainless steel tanks exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) 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
3.2.1-100	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. SPS has 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. See further evaluation in Section 3.2.2.2.8.
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)	Not applicable. SPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation (external) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used. 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. SPS has 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. See further evaluation in Section 3.2.2.2.8.

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 with exceptions. Cracking of stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation. 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. SPS has 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. SPS has 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. See further evaluation in Section 3.2.2.2.10.

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
3.2.1-106	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 with exceptions. Loss of material of stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation. See further evaluation in Section 3.2.2.2.2.
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 components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) 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 components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) 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. SPS has 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. See further evaluation in Section 3.2.2.2.8.
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. SPS has 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. See further evaluation in Section 3.2.2.2.8.
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. SPS has 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. See further evaluation in Section 3.2.2.2.10.

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)	Not applicable. SPS has no in-scope stainless steel or nickel alloy underground piping, piping components or tanks in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used. 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	Not applicable. SPS has no in-scope stainless steel or nickel alloy piping, piping components exposed to treated water >60°C (>140°F) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. SPS has 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. SPS has 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. SPS has 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. SPS has 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. SPS has 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. See further evaluation in Section 3.2.2.2.10.
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. SPS has 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. SPS has 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. See further evaluation in Section 3.2.2.2.10.
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. SPS has 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. SPS has 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. SPS has 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	Not applicable. SPS has no in-scope steel closure bolting exposed to soil, concrete or underground 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
3.2.1-126	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. SPS has 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. SPS has 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. SPS has 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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 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. SPS has 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. SPS has 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. SPS has 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. SPS has 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.

Intentionally Blank

Results Tables: Engineered Safety Features AMR Results

Table 3.2.2-1 Engineering Safety Features - Containment 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	LB;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) Condensation	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
Filter element	FLT	Stainless steel	(E) 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	B
Filter housing	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
Flow element	SI	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-451c	3.2.1-108	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-450c	3.2.1-107	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	B
Heat exchanger (refueling water refrigeration unit - shell)	SI	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-451c	3.2.1-108	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-450c	3.2.1-107	C
			(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	B

Table 3.2.2-1 Engineering Safety Features - Containment 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
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	C, 4
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 4
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A, 1
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	B, 1
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	V.A.EP-103d	3.2.1-007	E, 3
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	C, 4
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 4
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A

Table 3.2.2-1 Engineering Safety Features - Containment 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) Concrete	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-451c	3.2.1-108	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-450c	3.2.1-107	A
			(E) Soil	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	None	None	H, 3
				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	B
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A, 1
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	B, 1
Pump casing (chemical addition)	PB	Stainless steel	(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A, 1
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	B, 1
Pump casing (containment spray)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B

Table 3.2.2-1 Engineering Safety Features - Containment 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
Pump casing (refueling water recirculation)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
Sample sink	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
Spray nozzle	SP	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A
			(I) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.EP-38	3.2.1-008	A
Strainer body	PB	Stainless steel	(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A, 1
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	B, 1
Tank (chemical addition)	PB	Stainless steel	(E) Air – outdoor	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-446a	3.2.1-103	B
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-449a	3.2.1-106	B
			(I) Treated water	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.A.E-404	3.2.1-070	B, 1

Table 3.2.2-1 Engineering Safety Features - Containment 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
Tank (refueling water storage)	PB	Stainless steel	(E) Soil	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-405	3.2.1-067	B, 2
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-472	3.2.1-129	B, 2
			(E) Condensation	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-446a	3.2.1-103	B
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-449a	3.2.1-106	B
			(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	B
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	C, 4
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 4
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-451c	3.2.1-108	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-450c	3.2.1-107	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	B
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A, 1
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	B, 1

Table 3.2.2-1 Plant-Specific Note:

1. This treated water environment is a sodium hydroxide solution.
2. Represents exterior bottom of refueling water storage tanks.
3. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program to manage cracking in sensitized stainless steel components.
4. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

Table 3.2.2-2 Engineering Safety Features - Recirculation 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	LB;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
			(E) Waste water	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A, 2
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-418	3.2.1-076	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
Expansion joint	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C, 3
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 3
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C, 3
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 3
Heat exchanger (recirculation spray cooler - channel)	PB	Titanium (ASTM Grade 2)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-151	3.3.1-122	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-151	3.3.1-122	A

Table 3.2.2-2 Engineering Safety Features - Recirculation 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
Heat exchanger (recirculation spray cooler - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.EP-103d	3.2.1-007	C
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.EP-81c	3.2.1-048	C
Heat exchanger (recirculation spray cooler - tube)	HT;PB	Titanium (ASTM Grade 2)	(E) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-419	3.3.1-096a	A
			(I) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-419	3.3.1-096a	A
Heat exchanger (recirculation spray cooler - tubesheet)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 1
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.EP-103d	3.2.1-007	C, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.EP-81c	3.2.1-048	C, 1
		Titanium (ASTM Grade 2)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-151	3.3.1-122	A, 1
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-151	3.3.1-122	A, 1
Heat exchanger (seal cooler - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-424	3.2.1-081	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	C
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	D
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VIII.F.SP-100	3.4.1-018	A
					Water Chemistry (B2.1.2)	VIII.F.SP-100	3.4.1-018	B

Table 3.2.2-2 Engineering Safety Features - Recirculation 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
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C, 3
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 3
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	V.A.EP-103c	3.2.1-007	E, 4
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C, 3
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 3
			(E) Concrete	None	None	V.F.EP-20	3.2.1-091	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	B
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C, 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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.EP-77	3.2.1-049	A
					One-Time Inspection (B2.1.20)	V.A.EP-77	3.2.1-049	A

Table 3.2.2-2 Engineering Safety Features - Recirculation 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
Pump casing (recirculation spray)	PB	Stainless steel	(E) 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	B
			(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	B
Spray nozzle	SP	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A
			(I) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.EP-38	3.2.1-008	A
Sump screen	FLT	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C, 3
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 3
Tank (seal accumulator)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-442b	3.2.1-099	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	B

Table 3.2.2-2 Engineering Safety Features - Recirculation 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	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C, 3
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 3
			(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	B
		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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.EP-77	3.2.1-049	A
					One-Time Inspection (B2.1.20)	V.A.EP-77	3.2.1-049	A

Table 3.2.2-2 Plant-Specific Notes:

1. Recirculation spray heat exchangers have separate tube side and shell side tubesheets.
2. The recirculation suction sump is partially filled with demineralized water after outages. The sump is assumed to collect contaminants during normal operation, resulting in a waste water environment for external surfaces of suction piping and bolting within the sump.
3. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
4. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the External Surfaces Monitoring of Mechanical Components (B2.1.23) program to manage cracking in sensitized stainless steel components.

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	LB;PB	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
Heat exchanger (residual heat removal - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	D
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	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	B
Heat exchanger (residual heat removal - 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	B
Heat exchanger (residual heat removal - 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	B
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.D1.EP-96	3.2.1-033	B
			(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	D
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	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	B
				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	B

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 removal - 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	B
			(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	D
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	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	B
Heat exchanger (seal cooler - housing)	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	B
Heat exchanger (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	B
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.D1.EP-96	3.2.1-033	B
			(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	B
				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	B
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
				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	B
Piping, piping components	LB;PB	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	V.F.EP-10	3.2.1-057	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
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(E) Concrete	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(E) Soil	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	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	B
			(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	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A, 1, 2
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	B, 1
				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	B

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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
				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	B
Strainer body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
				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	B
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
			(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	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A, 1
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	B, 1
				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	B

Table 3.2.2-3 Plant-Specific Notes:

1. Reactor coolant pressure boundary components only. Environment is equivalent to reactor coolant for this aging evaluation.
2. Includes consideration of sensitized stainless steel.

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) Waste water	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-418	3.2.1-076	A, 4
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A, 4
		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
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
Flow element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
Heat exchanger (seal cooler - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-424	3.2.1-081	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	C
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	D
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VIII.F.SP-100	3.4.1-018	A
					Water Chemistry (B2.1.2)	VIII.F.SP-100	3.4.1-018	B

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
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B

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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	C, 5
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	C, 5
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	3.2.1-004	A
			(E) Concrete	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
				None	None	V.F.EP-20	3.2.1-091	A, 8
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(E) Soil	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	None	None	H, 7
				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	B

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	(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A, 2, 3, 6
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	B, 2, 3
					ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	B, 1, 2
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A, 1, 2
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	B, 1, 2
				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	B
			(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	B
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C, 4
		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
Pump casing (hydro test)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
Pump casing (low-head)	PB	Stainless steel	(E) 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	B
			(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	B

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
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	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	B
Tank (low-head pump seal accumulator)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-442b	3.2.1-099	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	B
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-103c	3.2.1-007	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.D1.EP-107b	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	B
			(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	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A, 2, 3
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	B, 2, 3
				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	B
			(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	B

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	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

Table 3.2.2-4 Plant-Specific Notes:

1. Reactor coolant pressure boundary small-bore piping.
2. Environment is equivalent to reactor coolant for this aging evaluation.
3. Reactor coolant pressure boundary components.
4. External surface of pump suction piping in containment sump. Pipe runs through lower sump and connects to suction strainer above normal sump operating water level, so internal pipe environment remains separate from lower sump water during normal operation.
5. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
6. Includes consideration of sensitized stainless steel.
7. Augmented inspections within the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will manage cracking of sensitized stainless steel.
8. Suction piping embedded in concrete from the containment sump is not exposed to groundwater, and has no aging effects requiring management.

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.

Intentionally Blank

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.

- Fuel Handling (Section 2.3.3.1)
- Fuel Pool Cooling (Section 2.3.3.2)
- Cranes and Hoists (Section 2.3.3.3)
- Service Water (Section 2.3.3.4)
- Circulating Water (Section 2.3.3.5)
- Bearing Cooling (Section 2.3.3.6)
- Chilled Water (Section 2.3.3.7)
- Component Cooling (Section 2.3.3.8)
- Neutron Shield Tank Cooling (Section 2.3.3.9)
- Primary Grade Water (Section 2.3.3.10)
- Instrument Air (Section 2.3.3.11)
- Primary and Secondary Plant Gas Supply (Section 2.3.3.12)
- Service Air (Section 2.3.3.13)
- Boron Recovery (Section 2.3.3.14)
- Chemical and Volume Control (Section 2.3.3.15)
- Incore Instrumentation (Section 2.3.3.16)
- Reactor Cavity Purification (Section 2.3.3.17)
- Sampling System (Section 2.3.3.18)
- Decontamination (Section 2.3.3.19)
- Drains Aerated (Section 2.3.3.20)
- Drains Gaseous (Section 2.3.3.21)
- Gaseous Waste (Section 2.3.3.22)
- Liquid and Solid Waste (Section 2.3.3.23)
- Plumbing (Section 2.3.3.24)
- Radiation Monitoring (Section 2.3.3.25)

- Vents Aerated (Section 2.3.3.26)
- Vents Gaseous (Section 2.3.3.27)
- Water Treatment (Section 2.3.3.28)
- Ventilation (Section 2.3.3.29)
- Leakage Monitoring (Section 2.3.3.30)
- Secondary Vents (Section 2.3.3.31)
- Vacuum Priming (Section 2.3.3.32)
- Containment Vacuum (Section 2.3.3.33)
- Fire Protection (Section 2.3.3.34)
- Hydrogen Gas (Section 2.3.3.35)
- Emergency Diesel Generator System (Section 2.3.3.36)
- Alternate AC (Section 2.3.3.37)
- Security (Section 2.3.3.38)
- Buildings and Structures (Section 2.3.3.39)
- Containment Access (Section 2.3.3.40)
- Electrical Power (Section 2.3.3.41)
- Helium Vacuum Drying (Section 2.3.3.42)
- Reactor Building Penetrations (Section 2.3.3.43)

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 - Fuel Handling - Aging Management Evaluation
- Table 3.3.2-2, Auxiliary Systems - Fuel Pool Cooling - Aging Management Evaluation
- Table 3.3.2-3, Auxiliary Systems - Cranes and Hoists - Aging Management Evaluation
- Table 3.3.2-4, Auxiliary Systems - Service Water - Aging Management Evaluation
- Table 3.3.2-5, Auxiliary Systems - Circulating Water - Aging Management Evaluation
- Table 3.3.2-6, Auxiliary Systems - Bearing Cooling - Aging Management Evaluation
- Table 3.3.2-7, Auxiliary Systems - Chilled Water - Aging Management Evaluation
- Table 3.3.2-8, Auxiliary Systems - Component Cooling - Aging Management Evaluation
- Table 3.3.2-9, Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation
- Table 3.3.2-10, Auxiliary Systems - Primary Grade Water - Aging Management Evaluation
- Table 3.3.2-11, Auxiliary Systems - Instrument Air - Aging Management Evaluation
- Table 3.3.2-12, Auxiliary Systems - Primary and Secondary Plant Gas Supply - Aging Management Evaluation
- Table 3.3.2-13, Auxiliary Systems - Service Air - Aging Management Evaluation
- Table 3.3.2-14, Auxiliary Systems - Boron Recovery - Aging Management Evaluation
- Table 3.3.2-15, Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation
- Table 3.3.2-16, Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation
- Table 3.3.2-17, Auxiliary Systems - Reactor Cavity Purification - Aging Management Evaluation
- Table 3.3.2-18, Auxiliary Systems - Sampling System - Aging Management Evaluation
- Table 3.3.2-19, Auxiliary Systems - Decontamination - Aging Management Evaluation
- Table 3.3.2-20, Auxiliary Systems - Drains Aerated - Aging Management Evaluation
- Table 3.3.2-21, Auxiliary Systems - Drains Gaseous - Aging Management Evaluation
- Table 3.3.2-22, Auxiliary Systems - Gaseous Waste - Aging Management Evaluation
- Table 3.3.2-23, Auxiliary Systems - Liquid and Solid Waste - Aging Management Evaluation
- Table 3.3.2-24, Auxiliary Systems - Plumbing - Aging Management Evaluation
- Table 3.3.2-25, Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation

3.3.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Fuel Handling

Materials

The materials of construction for the fuel handling system component types are:

- Copper Alloy
- Stainless steel

Environment

The fuel handling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the fuel handling system, require management:

- Cracking
- 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 (B2.1.32)
- ASME Section XI, Subsection IWE (B2.1.29)
- Bolting Integrity (B2.1.9)
- 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)

3.3.2.1.2 Fuel Pool Cooling

Materials

The materials of construction for the fuel pool cooling system component types are:

- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The fuel pool cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Concrete
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the fuel pool cooling 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 fuel pool 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)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.3 Cranes and Hoists

Materials

The materials of construction for the cranes and hoists system component types are:

- Stainless steel
- Steel

Environment

The cranes and hoists 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 cranes and hoists 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 cranes and hoists 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)
- Water Chemistry (B2.1.2)

3.3.2.1.4 Service Water

Materials

The materials of construction for the service water system component types are:

- Copper Alloy
- Copper Alloy (>8 percent Al)
- Copper Alloy (>15 percent Zn)
- Ductile iron with internal coating
- Elastomer
- Fiberglass
- Glass
- Gray cast iron
- Nickel Alloy
- Polymer
- PVC
- Stainless steel
- Stainless steel with internal lining
- Steel
- Steel with internal coating
- Steel with internal lining
- Titanium

Environment

The service water system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Condensation
- Diesel exhaust
- Fuel oil
- Raw water
- Soil
- Treated water
- Underground
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the service water system, require management:

- Cracking
- Cracking or blistering
- Cracking, blistering, loss of material
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- 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 (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- 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 (B2.1.28)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)

3.3.2.1.5 Circulating Water

Materials

The materials of construction for the circulating water system component types are:

- Concrete
- Copper Alloy (>15 percent Zn)
- Copper Alloy with internal coating
- Ductile iron with internal coating
- Elastomer
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating
- Steel with internal lining
- Titanium

Environment

The circulating water system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Condensation
- Raw water
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the circulating water system, require management:

- Cracking
- Flow blockage
- Hardening or loss of strength
- 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 circulating water system component types:

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.27)
- 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 (B2.1.28)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.6 Bearing Cooling

Materials

The materials of construction for the bearing cooling system component types are:

- Aluminum
- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Ductile iron
- Elastomer
- Glass
- Gray cast iron
- Polymer
- Stainless steel
- Steel
- Steel with internal lining

Environment

The bearing cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Condensation
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the bearing cooling system, require management:

- Cracking
- Cracking or blistering
- Hardening or loss of strength
- 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 bearing cooling system component types:

- Bolting Integrity (B2.1.9)
- 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)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.7 Chilled Water

Materials

The materials of construction for the chilled water system component types are:

- Copper Alloy
- Glass
- Gray cast iron
- Stainless steel
- Steel

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
- Lubricating oil
- Treated borated water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the chilled water 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 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)
- 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)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

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 percent Zn)
- Glass
- Gray cast iron
- Polymer
- Stainless steel
- Steel
- Steel with internal coating
- Steel with titanium cladding
- Titanium (ASTM Grade 2)

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
- Condensation
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the component cooling system, require management:

- Cracking
- Cracking or blistering
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

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)
- 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 (B2.1.28)
- 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 Neutron Shield Tank Cooling

Materials

The materials of construction for the neutron shield tank cooling system component types are:

- Stainless steel
- Steel

Environment

The neutron shield tank cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water

Aging Effects Requiring Management

The following aging effects, associated with the neutron shield tank cooling 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 neutron shield tank 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)

3.3.2.1.10 Primary Grade Water

Materials

The materials of construction for the primary grade water system component types are:

- Glass
- Stainless steel
- Steel

Environment

The primary grade water 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 primary grade water system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the primary grade water 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)
- Water Chemistry (B2.1.2)

3.3.2.1.11 Instrument Air

Materials

The materials of construction for the instrument air system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Elastomer
- Glass
- Gray cast iron
- Polymer
- 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
- Condensation
- Gas
- Lubricating oil
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the instrument air system, require management:

- Cracking
- Cracking or blistering
- 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 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)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.12 Primary and Secondary Plant Gas Supply

Materials

The materials of construction for the primary and secondary plant gas supply system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Gray cast iron
- Stainless steel
- Steel

Environment

The primary and secondary plant gas supply system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Gas
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the primary and secondary plant gas supply 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 primary and secondary plant gas 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)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.13 Service Air

Materials

The materials of construction for the service air system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Gray cast iron
- Stainless steel
- Steel

Environment

The service air system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation

Aging Effects Requiring Management

The following aging effects, associated with the 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 service air 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)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)

3.3.2.1.14 Boron Recovery

Materials

The materials of construction for the boron recovery system component types are:

- Gray cast iron
- Nickel Alloy
- Stainless steel
- Steel

Environment

The boron recovery 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 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 recovery 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 boron recovery 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)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.15 Chemical and Volume Control

Materials

The materials of construction for the chemical and volume control system component types are:

- Copper Alloy
- Copper Alloy with internal coating
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The chemical and volume control system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Concrete
- Gas
- Lubricating oil
- Raw water
- Soil
- 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
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

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)
- Buried and Underground Piping and Tanks (B2.1.27)
- 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)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- 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)
- Water Chemistry (B2.1.2)

3.3.2.1.16 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:

- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)

3.3.2.1.17 Reactor Cavity Purification

Materials

The materials of construction for the reactor cavity purification system component types are:

- Stainless steel
- Steel

Environment

The reactor cavity purification system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the reactor cavity purification system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the reactor cavity purification 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)
- Water Chemistry (B2.1.2)

3.3.2.1.18 Sampling System

Materials

The materials of construction for the sampling system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Elastomer
- Glass
- Gray cast iron
- Polymer
- Stainless steel
- Steel

Environment

The sampling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Gas
- Steam
- 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 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 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)

3.3.2.1.19 Decontamination

Materials

The materials of construction for the decontamination system component types are:

- Stainless steel
- Steel

Environment

The decontamination 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 decontamination system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the decontamination 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)

3.3.2.1.20 Drains Aerated

Materials

The materials of construction for the drains aerated system component types are:

- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The drains aerated 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 drains aerated system, require management:

- Cracking
- Flow blockage
- 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 drains aerated 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)

3.3.2.1.21 Drains Gaseous

Materials

The materials of construction for the drains gaseous system component types are:

- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The drains gaseous system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the drains gaseous system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the drains gaseous 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)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.22 Gaseous Waste

Materials

The materials of construction for the gaseous waste system component types are:

- Stainless steel
- Steel

Environment

The gaseous waste system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Condensation
- Gas
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the gaseous waste 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 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)

3.3.2.1.23 Liquid and Solid Waste

Materials

The materials of construction for the liquid and solid waste system component types are:

- Fiberglass
- Glass
- Nickel Alloy
- Stainless steel
- Steel
- Steel with nickel Alloy cladding

Environment

The liquid and solid waste system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Gas
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the liquid and solid waste system, require management:

- Cracking
- Cracking, blistering, loss of material
- 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 and solid waste 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)

3.3.2.1.24 Plumbing

Materials

The materials of construction for the plumbing system component types are:

- Copper Alloy
- Elastomer
- Fiberglass
- Gray cast iron
- Polymer
- PVC
- Stainless steel
- Steel

Environment

The plumbing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Raw water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the plumbing system, require management:

- Cracking
- Cracking or blistering
- Cracking, blistering, loss of material
- Flow blockage
- 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 plumbing system component types:

- Bolting Integrity (B2.1.9)
- 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)

3.3.2.1.25 Radiation Monitoring

Materials

The materials of construction for the radiation monitoring system component types are:

- Copper Alloy
- Stainless steel
- Steel

Environment

The radiation monitoring 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 radiation monitoring system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the radiation monitoring 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)

3.3.2.1.26 Vents Aerated

Materials

The materials of construction for the vents aerated system component types are:

- Stainless steel
- Steel

Environment

The vents aerated system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation

Aging Effects Requiring Management

The following aging effects, associated with the vents aerated system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the vents aerated 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)

3.3.2.1.27 Vents Gaseous

Materials

The materials of construction for the vents gaseous system component types are:

- Stainless steel
- Steel

Environment

The vents gaseous system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Gas

Aging Effects Requiring Management

The following aging effects, associated with the vents gaseous system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the vents gaseous 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)

3.3.2.1.28 Water Treatment

Materials

The materials of construction for the water treatment system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Elastomer
- Fiberglass
- Gray cast iron
- Gray cast iron with internal coating
- Nickel Alloy
- Polymer
- PVC
- Stainless steel
- Steel
- Steel with internal lining

Environment

The water treatment system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Raw water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the water treatment system, require management:

- Cracking
- Cracking or blistering
- Cracking, blistering, loss of material
- Hardening or loss of strength
- 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 water treatment 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 (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.29 Ventilation

Materials

The materials of construction for the ventilation system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Copper Alloy with internal coating
- Elastomer
- Gray cast iron
- Polymer
- Stainless steel
- Steel
- Steel with internal coating

Environment

The ventilation 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
- Concrete
- Condensation
- Gas
- Lubricating oil
- Raw water
- Steam
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the ventilation system, require management:

- Cracking
- Cracking or blistering
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the ventilation 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)
- Fire Protection (B2.1.15)
- 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 (B2.1.28)
- 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)
- Water Chemistry (B2.1.2)

3.3.2.1.30 Leakage Monitoring

Materials

The materials of construction for the leakage monitoring system component types are:

- Aluminum
- Copper Alloy
- Stainless steel
- Steel

Environment

The leakage monitoring system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the leakage monitoring system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the leakage monitoring 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)

3.3.2.1.31 Secondary Vents

Materials

The materials of construction for the secondary vents system component types are:

- Copper Alloy
- Gray cast iron
- Steel

Environment

The secondary vents 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 secondary vents system, require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the secondary vents 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)

3.3.2.1.32 Vacuum Priming

Materials

The materials of construction for the vacuum priming system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Fiberglass
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The vacuum priming system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Condensation
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the vacuum priming system, require management:

- Cracking
- Cracking, blistering, loss of material
- Flow blockage
- 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 vacuum priming system component types:

- Bolting Integrity (B2.1.9)
- 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)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.33 Containment Vacuum

Materials

The materials of construction for the containment vacuum system component types are:

- Steel

Environment

The containment vacuum system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Steam

Aging Effects Requiring Management

The following aging effects, associated with the containment vacuum system, require management:

- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the containment vacuum 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)

3.3.2.1.34 Fire Protection

Materials

The materials of construction for the fire protection system component types are:

- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Ductile iron
- Glass
- Gray cast iron
- Gray cast iron with internal lining
- Polymer
- Stainless steel
- Steel
- Steel with internal coating

Environment

The fire protection system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Diesel exhaust
- Fuel oil
- Gas
- Lubricating oil
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the fire protection system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- 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 fire protection system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- 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 (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Selective Leaching (B2.1.21)

3.3.2.1.35 Hydrogen Gas

Materials

The materials of construction for the hydrogen gas system component types are:

- Copper Alloy
- Gray cast iron
- Steel

Environment

The hydrogen gas system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Condensation
- Gas
- Steam
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the hydrogen gas system, require management:

- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the hydrogen gas system component types:

- Bolting Integrity (B2.1.9)
- 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)

3.3.2.1.36 Emergency Diesel Generator System

Materials

The materials of construction for the emergency diesel generator system component types are:

- Aluminum
- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Elastomer
- Glass
- Gray cast iron
- Nickel Alloy
- Polymer
- Stainless steel
- Steel

Environment

The emergency diesel generator system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Closed-cycle cooling water
- Concrete
- Condensation
- Diesel exhaust
- Fuel oil
- Lubricating oil
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the emergency diesel generator system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- 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 emergency diesel generator system component types:

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.27)
- 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)
- Selective Leaching (B2.1.21)

3.3.2.1.37 Alternate AC

Materials

The materials of construction for the alternate ac system component types are:

- Aluminum
- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The alternate ac system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Closed-cycle cooling water
- Condensation
- Diesel exhaust
- Fuel oil
- Lubricating oil

Aging Effects Requiring Management

The following aging effects, associated with the alternate ac system, require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the alternate ac system component types:

- Bolting Integrity (B2.1.9)
- 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)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.38 Security

Materials

The materials of construction for the security system component types are:

- Aluminum
- Copper Alloy
- Copper Alloy (>15 percent Zn)
- Elastomer
- Gray cast iron
- Polymer
- Stainless steel
- Steel

Environment

The security system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Closed-cycle cooling water
- Diesel exhaust
- Fuel oil
- Lubricating oil

Aging Effects Requiring Management

The following aging effects, associated with the security system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- 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 security system component types:

- Bolting Integrity (B2.1.9)
- Closed Treated Water Systems (B2.1.12)
- 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)

3.3.2.1.39 Buildings and Structures

Materials

The materials of construction for the buildings and structures system component types are:

- Steel

Environment

The buildings and structures system component types are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects, associated with the buildings and structures system, require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the buildings and structures system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)

3.3.2.1.40 Containment Access

Materials

The materials of construction for the containment access system component types are:

- Stainless steel
- Steel

Environment

The containment access system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Lubricating oil

Aging Effects Requiring Management

The following aging effects, associated with the containment access system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the containment access system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)

3.3.2.1.41 Electrical Power

Materials

The materials of construction for the electrical power system component types are:

- Copper Alloy
- Steel

Environment

The electrical power system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water

Aging Effects Requiring Management

The following aging effects, associated with the electrical power system, require management:

- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the electrical power system component types:

- Bolting Integrity (B2.1.9)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)

3.3.2.1.42 Helium Vacuum Drying

Materials

The materials of construction for the helium vacuum drying system component types are:

- Aluminum
- Stainless steel
- Steel

Environment

The helium vacuum drying 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 helium vacuum drying system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the helium vacuum drying 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)
- Water Chemistry (B2.1.2)

3.3.2.1.43 Reactor Building Penetrations

Materials

The materials of construction for the reactor building penetrations system component types are:

- Stainless steel
- Steel

Environment

The reactor building penetrations 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 reactor building penetrations system, require management:

- Cracking
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the reactor building penetrations system component types:

- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)

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 NUREG-0612 plant cranes 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 and 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 4.3.3, ANSI B31.1 Allowable Stress Analyses.

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 (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.

[3.3.1-003] [3.3.1-003a] – A review of SPS operating experience confirmed that cracking of nonregenerative heat exchanger tubing has not been identified at SPS.

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.

Cracking due to stress corrosion cracking is an aging effect requiring management for stainless steel components exposed to air or condensation in the Auxiliary Systems for SPS.

A review of SPS operating experience has confirmed that cracking of the external surfaces of stainless steel components in indoor air has occurred. Cracking was found at SPS and was attributed to chloride induced transgranular stress corrosion cracking. Cracking has been identified on the external surfaces of stainless steel heat exchangers, piping, and welds in the residual heat removal system in the Containments, as well as on safety injection instrument piping in the Unit 2 Safeguards Building.

Cracking of a ¾ inch SPS Unit 2 residual heat removal balance line was identified in 2002. The source of chloride contamination at this location was not determined. Cracking was found at the Unit 1 residual heat removal heat exchangers in 2007 and at the Unit 2 residual heat removal heat exchangers in 2010.

The exact source of chloride contamination of the residual heat removal surfaces is unknown. Chloride contamination most likely originated from the insulation, although a review of the original insulation specification identified that requirements did exist when installing insulation on austenitic stainless steel to minimize the possibility of chlorides leaching from the insulation. In addition to repair of the damaged areas, the insulation was removed and the surfaces were cleaned and verified to be free of detectable chlorides.

Cracking of an uninsulated SPS Unit 2 low-head safety injection discharge flow element sensing line was identified in 2004. The cause was determined to be chloride induced stress corrosion cracking from the outside diameter. The apparent source of contamination was rainwater leakage into the valve pits housing the piping. Corrective actions included replacement of the affected piping and performing inspections of similar piping to identify any additional cracking (none was found).

Because cracking was found at both units, the potential for chloride contamination could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for cracking of stainless steel in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.3.1-004] – Cracking of stainless steel components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the boron recovery, fuel handling, and leakage monitoring systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-094a] – Cracking of stainless steel ducting components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the ventilation system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-146] – SPS has no in-scope stainless steel underground piping, piping components or tanks in the Auxiliary Systems.

[3.3.1-205] – Cracking of insulated stainless steel components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. SPS has no insulated stainless steel piping, piping components exposed to air-outdoor in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.3.1-231] – SPS has 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 Auxiliary Systems.

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.

Loss of material due to pitting and crevice corrosion is an aging effect requiring management for stainless steel and nickel alloy components exposed to air or condensation in the Auxiliary Systems for SPS.

A review of SPS operating experience confirmed that loss of material of the external surfaces of stainless steel components in indoor air has occurred. Examples of externally initiated stress corrosion cracking are described in Section 3.3.2.2.3. Pitting was noted in some of the same general areas as cracking in the residual heat removal and safety injection systems.

Pitting and crevice corrosion of stainless steel and nickel alloy in air is supported by the presence of the same contaminants that support stress corrosion cracking. Since pitting was identified in some of the same general locations as cracking in the safety injection and residual heat removal systems, the potential for chloride contamination could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for loss of material due to pitting and crevice corrosion of stainless steel and nickel alloy in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[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 External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the fuel handling and leakage monitoring systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-094] – Loss of material of stainless steel components exposed to air, condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the ventilation system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-222] – Loss of material of stainless steel or nickel alloy tanks exposed to air-indoor uncontrolled or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

[3.3.1-228] – SPS has 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 Auxiliary Systems.

[3.3.1-232] – Loss of material of insulated stainless steel components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. SPS has no in-scope insulated nickel alloy piping, piping components exposed to air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.3.1-241] – Loss of material of stainless steel or nickel alloy heat exchanger components exposed to air-indoor uncontrolled or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the boron recovery system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-246] – SPS has no in-scope stainless steel or nickel alloy underground piping, piping components or tanks in the Auxiliary Systems.

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 and components exposed to raw water in the service water system, circulating water system, component cooling system (cooling water interfaces), fire protection system, plumbing system, and ventilation system (cooling water interfaces). The programs noted below will manage RIC in the systems indicated.

Open-Cycle Cooling Water System program (B2.1.11)

As described below, SPS will implement the Open-Cycle Cooling Water System program (B2.1.11) to manage aspects of RIC in the service water system and circulating water system that are within the scope of the program. The Internal Coatings/Linings for In-scope Piping, Piping Components, Heat Exchangers and Tanks program (B2.1.28) will manage loss of material on the internal surfaces of service water system and circulating water system piping that has been lined or coated and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) will manage loss of material on the internal surfaces of service water system and circulating water system piping not covered by NRC Generic Letter 89-13 and fabricated of elastomer or polymer material or not subject to internal inspections within the scope of the program. In addition, the Appendix B operating experience section for the Open-Cycle Cooling Water System (B2.1.11) 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 of RIC in piping and components within the scope of the Open-Cycle Cooling Water System program (B2.1.11) will be documented in accordance with the Corrective Action Program. The Open-Cycle Cooling Water System program (B2.1.11) 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:*

Flow Blockage:

Flow blockage in open-cycle cooling water (OCCW) piping and components is managed by periodically monitoring control room chiller Y-strainer differential pressure and periodically flushing affected piping flow paths. During times when service water temperatures are elevated above 80°F, the operations surveillance frequency of monitoring service water suction pressure and rotating strainer differential pressures are increased to intervals as short as once every 4 hours and piping flush frequency increased to intervals as short as daily. As a preventive measure, biocide injection points have been added downstream of the rotating suction strainers and the biocide injection has significantly reduced hydroid attachment and growth. A plant modification is in progress to add additional biocide injection points to the upstream portion of the service water rotating strainers.

Loss of Material in Uncoated Steel Piping:

Loss of material has resulted in recurrent wall thinning and through wall leakage in service water piping in uncoated steel service water piping associated with main control room chillers. Replacement of uncoated steel piping with corrosion resistant copper-nickel piping reduced the susceptibility of the OCCW systems to recurring internal corrosion. There has been no documented recurring internal corrosion on the control room chillers copper-nickel piping or other copper-nickel service water system piping within the scope of license renewal; therefore, additional augmented inspections are not required.

Loss of Material in Copper-Nickel Alloy Heat Exchanger Tubing:

Recurring internal corrosion (loss of material) was experienced in the copper-nickel alloy heat exchanger tubing at and beyond the tube sheet for the main control room chiller condensers, including a condenser that had been recently replaced. The affected heat exchanger components have been cleaned and coated with a protective epoxy coating with the coating extending six inches into the heat exchange tubes. The Corrective Action Program apparent cause evaluation identified that the heat exchanger management program did not require flow to be maintained for an extended period in new 90-10 copper-nickel alloy heat exchangers to permit a protective oxide film to form on the tubes prior to the placement of the heat exchangers into a stagnant wet lay-up condition. Implementing documents have been modified to incorporate this lesson-learned. After epoxy coating and modification of wet layup practices, there has been no documented recurring internal corrosion in the control room chiller condenser copper-nickel alloy tubing at and beyond the tube sheet; therefore, additional augmented inspections are not required.

Loss of Material in Coated Steel Piping and Heat Exchanger Channel Heads:

See the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program discussion in this further evaluation section for recurring internal corrosion details. Corrosion-resistant Carbon Fiber Reinforced Polymer (CFRP) liner has been installed on the component cooling water heat exchanger discharge piping and the main condenser discharge piping. CFRP liner will be installed in the 96-inch circulating water inlet piping, and 24-, 30-, 36-, 42-, and 48-inch service water supply from the circulating water system to the recirculation spray and supply to the component cooling water heat exchangers. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will manage the aging of CFRP in the OCCW systems. For epoxy coated piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will manage the aging of the existing epoxy-coated steel piping.

b) *Basis for the adequacy of augmented or lack of augmented inspections:*

The frequency of strainer differential pressure monitoring and piping flushes is increased during times of elevated service water system temperature and vulnerability to flow blockage before loss of intended function. Additionally, biocide injection has significantly reduced biological fouling factors in the system.

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 is not required. The frequency of strainer differential pressure monitoring and piping flushes is increased during times of elevated service water system temperature and vulnerability to flow blockage before loss of intended function.

d) *How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:*

Service water strainers are accessible for monitoring. In addition, affected piping flow paths are accessible for flushing.

e) *How leaks in any involved buried or underground components will be identified:*

Strainers and associated flushing flow paths are not located in buried or underground environments.

Fire Water System program (B2.1.16)

As described below, SPS will implement the Fire Water System program (B2.1.16) to manage RIC in the fire protection system. In addition, the Appendix B operating experience section for the Fire Water System program (B2.1.16) 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 program (B2.1.16) will be documented in accordance with the Corrective Action Program. The Fire Water System program (B2.1.16) 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. Periodic visual inspections and tank bottom thickness measurements are performed on the fire water storage tanks. In addition to recent piping replacements in the Turbine Building and the Auxiliary 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. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. 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 or tank 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 flushes 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 cast iron cement-lined pipe. In September 2014, a materials analysis was performed due to a failure initiated by a manufacturing defect in the cast iron portion of the buried fire main piping. The analysis found the balance of the cast iron cement-lined pipe to be in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter. Future inspections on underground fire main piping will be performed on an opportunistic basis when corrective maintenance work is performed on the fire water 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 is alarmed in the 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 exist. The status of the fire pumps is indicated in the control room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the 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.

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25)

As described below, SPS will implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) to manage RIC in portions of the plumbing system and unlined/uncoated portions of the service water system. In addition, the Appendix B operating experience section for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) 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 program (B2.1.25) will be documented in accordance with the Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) 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:*

Sections of service water piping not within the scope of GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” that have had documented leaks in the past due to corrosion of steel from a raw water environment have been replaced or repaired. Opportunistic inspections of susceptible piping and components will be performed when the system boundary is opened. Periodic system walkdowns in accordance with plant procedure will monitor for leakage.

Work orders have been created to replace affected portions of the plumbing system piping along an approximately 77 foot length in the Unit 1Turbine Building basement that have documented leaks from corrosion due to stagnant water in the lines.

b) *Basis for the adequacy of augmented or lack of augmented inspections:*

Service water piping not within the scope of GL 89-13 that has had documented leaks in the past is in lower pressure applications, such as vents and drains on gravity-fed heat exchangers. Opportunistic inspections of susceptible piping and components when the system boundary is opened, along with periodic system walkdowns are sufficient to detect aging effects. Piping sections that demonstrate significant aging effects in the inspections will be replaced.

The plumbing system piping that has documented leaks will be replaced, which obviates the need for augmented inspections. Opportunistic inspections of susceptible piping and components in other portions of the system within the scope of subsequent license renewal will continue to be performed when the system boundary is opened.

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):*

The condition of the service water piping not within the scope of GL 89-13 will be assessed during opportunistic inspections with occurrences of aging effects recorded in the Corrective Action Program. The need for increased inspections and repair or replacement will be evaluated as part of the corrective actions, considering the extent and rate of degradation.

The condition of the plumbing system piping will be assessed during opportunistic inspections following replacement with occurrences of aging effects recorded in the Corrective Action Program. The need for increased inspections and subsequent repair or replacement will be evaluated as part of the corrective actions, considering the extent and rate of degradation.

d) *How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:*

Service water piping not within the scope of GL 89-13 that has had documented leaks in the past is not located in buried or underground environments. The affected piping and other similar potentially susceptible service water piping not within the scope of GL 89-13 are in lower pressure applications such as vents and drains that are accessible for inspection.

The plumbing system piping that has had documented leakage in the past is not located in buried or underground environments. The affected piping is in the Unit 1 Turbine Building basement that is accessible for inspection.

e) *How leaks in any involved buried or underground components will be identified:*

Service water piping not within the scope of GL 89-13 that has had documented leaks in the past is not located in buried or underground environments. The affected piping and other similar potentially susceptible service water piping not within the scope of GL 89-13 are in lower pressure applications such as vents and drains, so that leaks can be identified with visual inspections.

The plumbing system piping that has had documented leakage in the past is not located in buried or underground environments. The affected piping is in the Unit 1 Turbine Building basement, so that leaks can be identified with visual inspections.

<u>Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program</u> (B2.1.28)

As described below, SPS will implement the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) to manage RIC in the circulating water and service water systems. In addition, the Appendix B operating experience section for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) 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 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) will be documented in accordance with the Corrective Action Program. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) 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:*

Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with carbon fiber reinforced polymer (CFRP). The design changes for both units are in progress, and no documented aging effects for CFRP coated sections of the 96-inch circulating water outlet piping have been identified. The CFRP design changes will be completed over the next several refueling outages. Separate design changes will install CFRP in the 96-inch circulating water inlet piping and the 24-, 30-, 36-, 42-, and 48-inch service water piping from the circulating water system to the recirculation spray and supply for the component cooling heat exchangers. For epoxy coated piping sections and main condenser channel heads that do not yet have the CFRP lining installed, inspection is performed of approximately 25 percent of the circulating water and service water system internal coatings each refueling cycle, thereby 100 percent of all the circulating water and service water system piping is inspected every 6 years.

The component cooling heat exchanger channel heads are epoxy-coated steel exposed to raw water (service water). Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal.

b) *Basis for the adequacy of augmented or lack of augmented inspections:*

The CFRP lining is designed to meet the existing design requirements for the lines in which it will be installed and will serve as the system pressure boundary. The CFRP is not susceptible to pitting in a raw water environment as the existing steel pipe is. Therefore, augmented inspections will not be necessary on piping lined with CFRP. For piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, inspection of approximately 25 percent of the circulating water and service water system internal coatings each refueling cycle provides an adequate sample size for detecting aging effects prior to loss of intended function. As a result of the inspection protocol with a 25 percent sample population, 100 percent of the circulating water and service water internal coatings is inspected every 6 years.

Plant operating experience has demonstrated that the yearly inspections of the component cooling heat exchanger channel heads are frequent enough to detect degradation before causing a loss of intended function.

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):*

The condition of the internal coatings of the circulating water and service water system (including CFRP) will be assessed during scheduled inspections, and any degraded conditions recorded in the Corrective Action Program. The need for increased inspections will be evaluated as part of the corrective actions, considering past inspection results, extent of degradation, and rate of degradation.

Any degradation of the heat exchanger channel head coatings or metal is recorded in the Corrective Action Program. The need for increased inspections will be evaluated as part of the corrective actions, considering past inspection results, extent of degradation, and rate of degradation.

d) *How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:*

Internal access is available to allow inspection of internal surfaces of portions of the circulating water and service water system piping that are buried and will be lined with CFRP.

Heat exchanger channel heads with coatings are not located in buried or underground environments. The interior surfaces of the heat exchanger channel heads are accessible for inspection.

e) *How leaks in any involved buried or underground components will be identified:*

Internal access is available to allow inspection of internal surfaces of portions of the circulating water and service water system piping that are buried and will be lined with CFRP. Internal coating degradation and substrate metal degradation are identified with visual inspections.

Heat exchanger channel heads with coatings are not located in buried or underground environments. Heat exchanger channel head leakage can be identified with visual inspections.

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 or condensation in the Auxiliary Systems for SPS.

A review of SPS operating experience did not identify a history of cracking of aluminum alloy components. However, operating experience as discussed in Sections 3.3.2.2.3 and 3.3.2.2.4 confirmed that the external surfaces of some stainless steel components have experienced aging that was supported by the presence of halides.

Stress corrosion cracking of susceptible aluminum alloys in air is supported by the presence of the same contaminants that support loss of material and cracking in stainless steel. Since these aging effects have been identified in some stainless steel components, the potential for chloride contamination of aluminum alloy surfaces could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for cracking due to stress corrosion cracking of aluminum alloys in air or condensation environments is assessed to exist at SPSin aging evaluations performed for subsequent license renewal.

[3.3.1-186] – SPS has 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.

[3.3.1-189] – Cracking of aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. The internal surfaces of some components in the emergency diesel generator system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-192] – SPS has no in-scope aluminum underground piping, piping components, tanks in the Auxiliary Systems.

[3.3.1-233] – SPS has no in-scope insulated aluminum piping, piping components, tanks exposed to an external environment of air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.3.1-254] – Cracking of aluminum heat exchanger components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, or 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 (steel only), crevice, or pitting corrosion, and cracking due to SCC (stainless steel only) can occur in steel and stainless steel components exposed to concrete.

[3.3.1-112] – Loss of material of steel piping components or structural steel with an external environment of concrete that do not exit the concrete into soil is not an applicable aging effect requiring management. Steel components that do not exit the concrete into soil are not potentially exposed to groundwater. Steel ventilation damper housings and structural steel embedded in reinforced concrete within building walls are not potentially exposed to groundwater. The concrete in areas containing these components conforms to ACI 349 or ACI 318. Review of SPS operating experience did not identify degradation of concrete around embedded components that could lead to penetration of water.

Loss of material can occur for steel piping components with an external environment of concrete that are potentially exposed to groundwater. Embedded piping that exits concrete into soil is potentially exposed to groundwater. Loss of material for steel components with an external environment of concrete that exit the concrete into soil is managed by the Buried and Underground Piping and Tanks (B2.1.27) program as identified in item [3.3.1-109].

[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 reactor cavity purification and fuel pool cooling systems are embedded within interior concrete structures in the reactor cavity and fuel pool, and are not potentially exposed to groundwater. Stainless steel fuel pool liner and structural elements associated with the fuel pool that are exposed to concrete are also not potentially exposed to groundwater.

Loss of material and cracking can occur for stainless steel piping components with an external environment of concrete that are potentially exposed to groundwater. Embedded piping that exits concrete into soil is potentially exposed to groundwater. Loss of material and cracking for stainless steel components with an external environment of concrete that exit the concrete into soil is managed by the Buried and Underground Piping and Tanks (B2.1.27) program as identified in items [3.3.1-107] and [3.3.1-144].

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 due to pitting and crevice corrosion is an aging effect requiring management for aluminum alloy components exposed to air and condensation in the Auxiliary Systems for SPS

A review of SPS operating experience did not identify a history of loss of material of in-scope aluminum alloy components. However, operating experience as discussed in Sections 3.3.2.2.3 and 3.4.2.2.4 confirmed that the external surfaces of some stainless steel components have experienced aging that was supported by the presence of halides.

Pitting and crevice corrosion of aluminum alloys in air is supported by the presence of the same contaminants that support loss of material and cracking in stainless steel. Since these aging effects have been identified in some stainless steel components, the potential for chloride contamination of aluminum alloy surfaces could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for loss of material due to pitting and crevice corrosion of aluminum alloys in air or condensation environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.3.1-223] – SPS has no in-scope aluminum underground piping, piping components or tanks in the Auxiliary Systems.

[3.3.1-227] – SPS has 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 Auxiliary Systems.

[3.3.1-234] – Loss of material of aluminum components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. The internal surfaces of some components in the emergency diesel generator system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-240] – SPS has no in-scope aluminum heat exchanger components exposed to waste water in the Auxiliary Systems.

[3.3.1-242] – Loss of material of aluminum heat exchanger components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

[3.3.1-245] - SPS has no in-scope insulated aluminum piping, piping components, or tanks exposed to an external environment of air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.3.1-247] – SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Auxiliary Systems.

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 components 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 or steel components is a TLAA. See further evaluation in Section 3.3.2.2.1. In addition to Auxiliary Systems, components in Steam and Power Conversion Systems (auxiliary steam, blowdown, condensate, extraction steam, main steam and steam drains) are aligned to this item.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. 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 stainless steel heat exchanger tubing, non-regenerative exposed to treated borated water >60°C (>140°F) is addressed in item 3.3.1-003. The associated NUREG-2191 aging items are not used. 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 or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the boron recovery, circulating water, fuel handling, and leakage monitoring systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. 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 or nickel alloy components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the circulating water, fuel handling, and leakage monitoring systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. 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.

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
3.3.1-008	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.
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. SPS has 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.

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
3.3.1-017	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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. Cracking of stainless steel components exposed to treated borated water >60°C (>140°F) is addressed in item 3.3.1-124. SPS does not have stainless steel high-pressure pump casing, piping, piping components, tanks exposed to sodium pentaborate solution >60°C (>140°F) 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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.

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
3.3.1-025	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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.

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
3.3.1-030a	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	Consistent with NUREG-2191, with exceptions, for cracking, blistering and loss of material. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation. In addition to Auxiliary Systems, components in Low Level Intake Structure are aligned to this item. Cracking, blistering and loss of material of trash racks in Low Level Intake Structure is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.

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
3.3.1-040	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow, or for strainer elements that are monitored for clogging.
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 with exceptions. Cracking (titanium only) and reduction of heat transfer of copper alloy or titanium heat exchanger tubes exposed to raw water is managed by the Open-Cycle Cooling Water System (B2.1.11) program. Cracking of titanium components other than heat exchanger tubes exposed to treated water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
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	Not applicable. SPS has no in-scope stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope stainless steel or steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F) 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
3.3.1-045	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation. In addition to Auxiliary Systems, components in Steam and Power Conversion System (heating) are aligned to this item.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation. In addition to Auxiliary Systems, components in Steam and Power Conversion System (heating) are aligned to this item.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.

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. SPS has no in-scope Boraflex spent fuel storage racks: neutron-absorbing sheets exposed to treated borated water, 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 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 Auxiliary Building Structure, Service Building and Turbine Building 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 program for some components. No Auxiliary Systems components are aligned to this item. Only components in Containment, Auxiliary Building Structure, High Level Intake Structure, Low Level Intake Structure, Service Building and Turbine Building are aligned to this item. For concrete elements in Containment, the ASME Section XI, Subsection IWL (B2.1.30) and Fire Protection (B2.1.15) programs are used to manage cracking and loss of material for the Containment reinforced concrete.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.
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. SPS has 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 with exceptions, and with a different program for some components. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation. Loss of material of stainless steel chemical addition components in the service water system exposed to treated water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.
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 with exceptions. Loss of material of copper alloy 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. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B2.1.18) program implementation.
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 with exceptions. Loss of material of steel components exposed to fuel oil is managed by the Fuel Oil Chemistry (B2.1.18) program. In addition to Auxiliary Systems, components in Steam and Power Conversion System (heating) are aligned to this item. For the heating system, loss of material of steel 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. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B2.1.18) program implementation.

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
3.3.1-071	Stainless steel, aluminum 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 with exceptions. Loss of material of stainless steel or aluminum alloy components exposed to fuel oil is managed by the Fuel Oil Chemistry (B2.1.18) program and One-Time Inspection (B2.1.20) program. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B2.1.18) program implementation. In addition to Auxiliary Systems, components in Steam and Power Conversion System (heating) are aligned to this item.
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. In addition to Auxiliary Systems, components in Steam and Power Conversion System (electro hydraulic control, heating, lubricating oil and steam drains) are aligned to this item.
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. SPS has no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to air – outdoor 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
3.3.1-076	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. The internal surfaces of some components in the instrument air, security, and ventilation systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.
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. The internal surfaces of some components in the boron recovery, fire protection, service water and ventilation systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.
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	Not applicable. Loss of material of steel components exposed to air – indoor uncontrolled or air – outdoor is addressed in item 3.3.1-078. The associated NUREG-2191 aging items are not used.
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. The internal surfaces of some components in the instrument air, security, vacuum priming, and ventilation systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.
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. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
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 components exposed to condensation (internal) is addressed in items 3.3.1-055 and 3.3.1-090. Loss of material for the internal surfaces of drained fire protection components is addressed in item 3.3.1-136. 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.

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
3.3.1-091	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 requiring management for nonsafety-related components that do not support a function of delivering downstream flow. In addition to Auxiliary Systems, components in the Steam and Power Conversion Systems (condensate polishing, heating, lubricating oil and steam drains) are aligned to this item.
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 components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the ventilation system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. 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
3.3.1-094a	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 components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the ventilation system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. 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. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow. In addition to Auxiliary Systems, components in the Steam and Power Conversion Systems (condensate polishing, lubricating oil and steam drains) are aligned to this item.
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. Flow blockage is not an applicable aging effect requiring management for components in an air environment, or for nonsafety-related components that do not support a function of delivering downstream flow.
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. In addition to Auxiliary Systems, components in the Engineered Safety Features (recirculation spray) are aligned to this item.
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.

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
3.3.1-097	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. SPS has no in-scope aluminum heat exchanger tubes exposed to lubricating oil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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	Not applicable. SPS has no in-scope Boral, boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets exposed to treated borated water 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
3.3.1-103	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	Consistent with NUREG-2191.
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	Consistent with NUREG-2191.
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	Consistent with NUREG-2191.
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.
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.

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
3.3.1-110	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. Loss of material of structural steel elements exposed to air-indoor uncontrolled is addressed in item 3.5.1-077 or item 3.5.1-083. 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. In addition to Auxiliary Systems, components in the Containment, Auxiliary Building Structure, Fuel Building Structure, High Level Intake Structure, Low Level Intake Structure and Miscellaneous Structural Commodities are aligned to this item. 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. SPS has 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.
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 piping components. SPS does not have copper alloy (>8% Al) components exposed to air with borated water leakage in the Auxiliary Systems. 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. SPS has no in-scope galvanized steel piping, piping components exposed to air – indoor uncontrolled in the Auxiliary Systems. For galvanized steel components, SPS used the material name “steel.” 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
3.3.1-117	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. In addition to Auxiliary Systems, components in the Steam and Power Conversion System (lubricating oil) are aligned to this item.
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.
3.3.1-122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in the Engineered Safety Features (recirculation spray) 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
3.3.1-123	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	Consistent with NUREG-2191 with exceptions. Cracking and flow blockage of titanium components exposed to raw water is managed by the Open-Cycle Cooling Water System (B2.1.11) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Auxiliary Systems, components in the 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 closed-cycle cooling water, 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 with exceptions, and with a different program used for some components. Loss of material due to recurring internal corrosion in raw water or waste water is managed by the Open-Cycle Cooling Water System (B2.1.11) program, the Fire Water System (B2.1.16) program, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program, or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. Recurring internal corrosion has not been identified at SPS in closed-cycle cooling water or treated water. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program and Open-Cycle Cooling Water System (B2.1.11) program implementation. 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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.

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
3.3.1-131	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.
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 insulated steel and copper alloy (>15% Zn or >8% Al) components and cracking of insulated copper alloy (>15% Zn or >8% Al) components exposed to air-outdoor or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.
3.3.1-133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. SPS has no in-scope HDPE underground piping, piping components in the Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.3.
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 requiring management for nonsafety-related components that do not support a function of delivering 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
3.3.1-135	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. The internal surfaces of some components in the plumbing system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. In addition to Auxiliary Systems, components in the Engineered Safety Features (recirculation spray and safety injection) are aligned to this item.
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.
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	Not applicable. SPS has no in-scope 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 in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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	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 with a different program for the fire protection and domestic water storage tanks. Loss of coating or lining integrity of the fire protection and domestic water storage tanks will be managed by the Fire Water System (B2.1.16) program. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation. In addition to Auxiliary Systems, components in the Reactor Vessel, Internals, And Reactor Coolant System (reactor coolant) and Steam and Power Conversion System (condensate polishing) 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
3.3.1-139	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	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 with a different program for the fire protection and domestic water storage tanks. Loss of material of the fire protection and domestic water storage tanks will be managed by the Fire Water System (B2.1.16) program. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation. In addition to Auxiliary Systems, components in the Reactor Vessel, Internals, And Reactor Coolant System (reactor coolant) and Steam and Power Conversion System (condensate polishing) are aligned to this item.
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/bicarbonat e environment only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.
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.

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. SPS has 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	Not applicable. SPS has no in-scope nickel alloy, nickel alloy cladding piping, piping components exposed to closed-cycle cooling water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-149	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. SPS has no in-scope fiberglass piping, piping components, ducting or 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	Consistent with NUREG-2191. The internal surfaces of some components in the vacuum priming system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. In addition to Auxiliary Systems, components in the Steam and Power Conversion System (condensate polishing) are aligned to this item.
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	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
3.3.1-155	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	Not applicable. SPS has no in-scope stainless steel piping, piping components or tanks exposed to waste water >60°C (>140°F) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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 piping, piping components, heat exchanger components exposed to air - outdoor is addressed in item 3.3.1-058 or item 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. SPS has no in-scope nickel alloy piping, piping components or heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water in the Auxiliary Systems. 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. Loss of material of fiberglass piping, piping components, ducting, ducting components exposed to air is addressed in item 3.3.1-082. 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 exceptions, for copper alloy (>15% Zn) exposed to raw water with ammonia treatment or exposed to waste water environments. Cracking of copper alloy (>15% Zn) exposed to raw water with ammonia treatment is managed by the Open-Cycle Cooling Water System (B2.1.11) program. Cracking of copper alloy (>15% Zn) components exposed to waste water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Cracking of copper alloy (>15% Zn or >8% Al) components exposed to raw water or closed-cycle cooling water requires the presence of ammonia or ammonium compounds. These contaminants are not present in the closed-cycle cooling water chemistries or in raw water environments at SPS except at the recirculation spray heat exchangers. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
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. SPS has 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. SPS has 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Auxiliary Systems, components in the Steam and Power Conversion System (extraction steam and heating) are aligned to this item.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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. SPS has 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	Consistent with NUREG-2191. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow. In addition to Auxiliary Systems, components in the Steam and Power Conversion Systems (condensate polishing) are aligned to this item.
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. Loss of material and flow blockage of fiberglass piping, piping components exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, or waste water is addressed in item 3.3.1-175. 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	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
3.3.1-178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not applicable. SPS has 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 Auxiliary Building Structure, Low Level Intake Structure, Service Building and Turbine Building are aligned to this item.
3.3.1-181	Titanium piping, piping components exposed to condensation	None	None	No	Not applicable. SPS has 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	Not applicable. SPS has no in-scope non-metallic thermal insulation exposed to air or condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. SPS has 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. SPS has 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. SPS has 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. See further evaluation in Section 3.3.2.2.8.
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 piping, piping components, tanks exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program, or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Auxiliary Systems. The internal surfaces of some components in the emergency diesel generator system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. See further evaluation in Section 3.3.2.2.8.

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
3.3.1-192	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. SPS has no in-scope aluminum underground piping, piping components, tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.8.
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. In addition to Auxiliary Systems, components in the Steam and Power Conversion Systems (condensate polishing, heating, and lubricating oil) are aligned to this item.
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. SPS has no in-scope PVC piping, piping components, or 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. Cracking, loss of material and flow blockage of concrete, concrete cylinder piping, reinforced concrete, asbestos cement or cementitious piping, piping components exposed to raw water, treated water or raw water (potable) is addressed in item 3.3.1-030. 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
3.3.1-196	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. SPS has 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. SPS has no in-scope metallic fire water system piping, piping components, heat exchanger, heat exchanger components with only a leakage boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil, concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope metallic fire water system piping, piping components, heat exchanger, heat exchanger components with only a leakage boundary (spatial) or structural integrity (attached) intended function in the Auxiliary Systems. 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. In addition to Auxiliary Systems, components in the Fuel Building Structure are aligned to this item. See further evaluation in Section 3.3.2.2.9.

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
3.3.1-203	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.
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 insulated stainless steel components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. SPS has no insulated stainless steel piping, piping components exposed to air-outdoor in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. 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	Consistent with NUREG-2191. Reduction of heat transfer is not an applicable aging effect for heat exchanger tubes that do not have a heat transfer function.

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
3.3.1-208	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. SPS has 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.
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. SPS has 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. SPS has 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. SPS has 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. SPS has 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.

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
3.3.1-218	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. SPS has 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 or nickel alloy tanks exposed to air-indoor uncontrolled or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) 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. SPS has no in-scope aluminum underground piping, piping components or tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.10.

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
3.3.1-226	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. SPS has 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.
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. SPS has 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 Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.10.
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. SPS has 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 Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.4.
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	Not applicable. SPS has 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 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
3.3.1-230	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	Not applicable. SPS has 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 Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. SPS has 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 Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.3.
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 insulated stainless steel components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. SPS has no in-scope insulated nickel alloy piping, piping components exposed to air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. 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
3.3.1-233	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. SPS has no in-scope insulated aluminum piping, piping components, or tanks exposed to an external environment of air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.8.
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 or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. The internal surfaces of some components in the emergency diesel generator system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. 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 the Engineered Safety Features (residual heat removal) and Steam and Power Conversion Systems (feedwater) 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
3.3.1-236	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	Consistent with NUREG-2191. with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. Reduction of heat transfer is not an applicable aging effect for heat exchanger tubes that do not have a heat transfer function.
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. SPS has 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 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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.
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. SPS has 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 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
3.3.1-240	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. SPS has no in-scope aluminum heat exchanger components exposed to waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.10.
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 or nickel alloy heat exchanger components exposed to air-indoor uncontrolled or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the boron recovery system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. 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)	Consistent with NUREG-2191. Loss of material of aluminum heat exchanger components (fins) exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, or 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.
3.3.1-244	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. SPS has no in-scope insulated aluminum piping, piping components, or tanks exposed to an external environment of air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.10.

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. SPS has 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. See further evaluation in Section 3.3.2.2.4.
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)	Not applicable. SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used. 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. 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. In addition to Auxiliary Systems, components in the Steam and Power Conversion Systems (auxiliary steam, blowdown and extraction steam) 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
3.3.1-250	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. SPS has no in-scope steel reactor coolant pump oil collection system tanks or 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. SPS has no in-scope aluminum piping, piping components exposed to soil, 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	Consistent with NUREG-2191 for loss of material with a different program credited for some components. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow. Loss of material and flow blockage of PVC piping, piping components exposed to raw water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Loss of material for external surfaces of submerged PVC sump pump discharge piping is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.
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)	Consistent with NUREG-2191. Cracking of aluminum heat exchanger components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, or 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.

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 and loss of strength, and shrinkage are not aging effects requiring management for steel fire dampers exposed to indoor air.
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	Consistent with NUREG-2191.
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. SPS has 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.

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
3.3.1-261	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. Cracking of titanium (ASTM Grade 2) heat exchanger tubes exposed to closed-cycle cooling water is addressed in item 3.3.1-238. Cracking of titanium (ASTM Grade 2) heat exchanger tubes exposed to raw water is addressed in item 3.3.1-042. Cracking of titanium (no grade identified) heat exchanger tubes exposed to raw water is addressed in item 3.3.1-207. The associated NUREG-2191 aging items are not used.
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. Cracking of titanium heat exchanger components exposed to closed-cycle cooling water or treated water is addressed in items 3.3.1-236 and 3.3.1-238. 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. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow. Hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components exposed to air, condensation, raw water, treated water or waste water is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the fire protection system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

Intentionally Blank

Results Tables: Auxiliary Systems AMR Results

Table 3.3.2-1 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
Blind flange (fuel transfer tube)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) 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	D
Bolting	PB	Copper alloy	(E) Air – indoor uncontrolled	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Stainless steel	(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
Expansion joint	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	C, 1
			(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	B
Fuel transfer tube	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-221c	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	B
			(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	B

Table 3.3.2-1 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 enclosure	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	C, 1
			(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	B
Valve body	PB	Stainless steel	(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	B
			(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	B

Table 3.3.2-1 Plant-Specific Note:

1. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

Table 3.3.2-2 Auxiliary Systems - Fuel Pool 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	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 (fuel pit ion exchanger - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Heat exchanger (fuel pit cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D

Table 3.3.2-2 Auxiliary Systems - Fuel Pool 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 (fuel pit 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	B
Heat exchanger (fuel pit cooler - 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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	B
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
				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	B
Heat exchanger (fuel pit cooler - tubesheet)	PB	Steel with stainless steel cladding	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated borated water	Loss of material	Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	B
Pump casing (spent fuel pit pump)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B

Table 3.3.2-2 Auxiliary Systems - Fuel Pool 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 pit purification pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Pump casing (spent fuel pit skimmer pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Strainer body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B

Table 3.3.2-2 Plant-Specific Notes: None

Table 3.3.2-3 Auxiliary Systems - Cranes and Hoists - 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	One-Time Inspection (B2.1.20)	III.B5.T-37a	3.5.1-100	A
Bolting	SS	Stainless steel	(E) Air – indoor uncontrolled	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
Bolting	SS	Stainless steel	(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-99	3.3.1-125	C
Bolting	SS	Stainless steel	(E) Treated borated water	Loss of material	Water Chemistry (B2.1.2)	VII.A2.A-99	3.3.1-125	D
Bolting	SS	Stainless steel	(E) Treated borated water	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
Bolting	SS	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
Bolting	SS	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
Crane rails and retaining clips, girders, beams, plates	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of material; cracking	One-Time Inspection (B2.1.20)	III.B5.T-37a	3.5.1-100	A
Crane rails and retaining clips, girders, beams, plates	SS	Stainless steel	(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-99	3.3.1-125	C
Crane rails and retaining clips, girders, beams, plates	SS	Stainless steel	(E) Treated borated water	Loss of material	Water Chemistry (B2.1.2)	VII.A2.A-99	3.3.1-125	D
Crane rails and retaining clips, girders, beams, plates	SS	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	VII.B.A-06	3.3.1-001	A
Crane rails and retaining clips, girders, beams, plates	SS	Steel	(E) Air – indoor uncontrolled	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
Crane rails and retaining clips, girders, beams, plates	SS	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

Table 3.3.2-3 Auxiliary Systems - Cranes and Hoists - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Lifting devices	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of material; cracking	One-Time Inspection (B2.1.20)	III.B5.T-37a	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	D
		Steel	(E) Air – indoor uncontrolled	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 3.3.2-3 Plant-Specific Note:

1. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13) program instead of the Structures Monitoring (B2.1.34) program will manage loss of preload of stainless steel structural bolting in cranes.

Table 3.3.2-4 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
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
Catch basin	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C
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
			(E) Condensation	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) 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, 2
				Loss of material; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-76	3.3.1-096	A, 2
		Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B

Table 3.3.2-4 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
Flexible hose	PB	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
		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.G.AP-234a	3.3.1-070	B
			(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	B
Flow element	LB;PB;RF	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	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B, 3
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 2, 3
		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	B, 3

Table 3.3.2-4 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	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) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B, 3
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-174	3.3.1-108	A
		Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(E) Condensation	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Raw water	Cracking, blistering, loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-238	3.3.1-030a	B, 3
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	None	None	H
			(E) Soil	Cracking, blistering, loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-176	3.3.1-104	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-462	3.3.1-177	A
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 2, 3

Table 3.3.2-4 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	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	B
		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) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 6
			(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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	B
			(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	B, 3
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 2, 3

Table 3.3.2-4 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	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
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(E) Condensation	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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-400	3.3.1-127	E, 4
						VII.C1.A-414	3.3.1-139	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
		Titanium	(E) Air – indoor uncontrolled	None	None	VII.J.AP-160	3.3.1-122	A
			(I) Raw water	Cracking; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-161b	3.3.1-123	A, 2, 3
			(I) Treated water	Cracking (titanium only); reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-187	3.3.1-042	C, 7

Table 3.3.2-4 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 (charging pump service water)	PB	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Pump casing (chemical injection skid)	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; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A, 3
				Loss of material; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A, 3
Pump casing (chemical metering)	LB	PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 2, 3
Pump casing (emergency service water)	PB	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B, 1
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B

Table 3.3.2-4 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 (recirculation spray heat exchanger service water radiation monitor)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Pump casing (river water make-up)	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) 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)	VIII.F.S-438	3.4.1-091	C, 2, 3
Separator	PB	Polymer	(E) Condensation	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) Raw water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 2
Sight glass	LB;PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A

Table 3.3.2-4 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
Sight glass (body)	LB;PB	PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 2, 3
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B, 3
		Titanium	(E) Air – indoor uncontrolled	None	None	VII.J.AP-160	3.3.1-122	A
			(I) Treated water	Cracking (titanium only); reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-187	3.3.1-042	C, 7
Spray shield	FLB	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	C
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 5

Table 3.3.2-4 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
Strainer 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) Condensation	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	B, 3
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 2, 3
		Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B, 3
		Titanium	(E) Air – indoor uncontrolled	None	None	VII.J.AP-160	3.3.1-122	A
			(I) Treated water	Cracking (titanium only); reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-187	3.3.1-042	C, 7
Strainer element	FLT	Stainless steel	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B, 1

Table 3.3.2-4 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
Tank (brominator mixing)	LB	Stainless steel with internal lining	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(I) Treated 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 (B2.1.28)	VII.H2.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.H2.A-414	3.3.1-139	A
Tank (diesel 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.G.AP-234a	3.3.1-070	B
Tank (pump pulsation dampener)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(I) Treated water	Loss of material; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-55	3.3.1-066	E, 8
Valve body	LB;PB	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) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B, 3
		Copper alloy (>8% Al)	(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-47	3.3.1-072	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B

Table 3.3.2-4 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	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	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	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Cracking	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-473b	3.3.1-160	B
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-47	3.3.1-072	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B, 3
		Ductile iron with internal coating	(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 6
			(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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
						VII.C1.A-415	3.3.1-140	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
			(E) Condensation	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	B, 3

Table 3.3.2-4 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	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B, 3
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 2, 3
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-136	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.G.AP-136	3.3.1-071	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	B
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 2, 3
			(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, 3

Table 3.3.2-4 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	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) Condensation	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	B
			(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	B
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 2, 3
		Steel with internal coating	(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-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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
		Titanium	(E) Air – indoor uncontrolled	None	None	VII.J.AP-160	3.3.1-122	A
			(I) Raw water	Cracking; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-161b	3.3.1-123	A, 2, 3
					Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-161a	3.3.1-123	B

Table 3.3.2-4 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for external surfaces or for strainer elements that are monitored for clogging.

2. For components not covered by NRC GL 89-13.

3. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

4. The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program is used instead of the Open-Cycle Cooling Water System program to manage recurring internal corrosion for internally-coated steel piping.

5. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

6. Cited GALL item VII.I.A-405a includes “cracking” aging effect that is only applicable for copper alloy (>15% Zn or >8% Al). Cracking is not an applicable aging effect for other materials.

7. Reduction of heat transfer is not applicable to components that do not have a heat transfer function.

8. Flow blockage is not applicable in treated water.

Table 3.3.2-5 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	LB;PB	Stainless 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
		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) 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
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
			(E) Air – outdoor	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) Condensation	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) 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 (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-76	3.3.1-096	A

Table 3.3.2-5 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
Heat exchanger (circulating water condenser - channel head)	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) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C, 8
			(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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-400	3.3.1-127	E, 6
						VII.C1.A-414	3.3.1-139	A
Heat exchanger (circulating water condenser - tube)	PB	Titanium	(I) Raw water	Cracking (titanium only); reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-736	3.3.1-207	A, 4
			(E) Treated water	Cracking; reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.C1.A-765	3.3.1-236	A, 4
					Water Chemistry (B2.1.2)	VII.C1.A-765	3.3.1-236	B, 4
Heat exchanger (circulating water condenser - tubesheet)	PB	Copper alloy with internal coating	(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	A, 5
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	A, 5
			(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	C, 5
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	D, 5

Table 3.3.2-5 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
Piping, piping components	LB;PB	Concrete	(I) Raw water	Cracking; loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-250	3.3.1-030	B
			(E) Soil	Cracking; loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-157	3.3.1-103	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 3
		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) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(E) Condensation	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 (B2.1.28)	VII.C1.A-416	3.3.1-138	A, 1
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-400	3.3.1-127	E, 6
						VII.C1.A-414	3.3.1-139	A
		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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A, 2

Table 3.3.2-5 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
Spray shield	FLB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C, 7
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	C, 7
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.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
		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
			(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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
						VII.C1.A-415	3.3.1-140	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
			(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, 3

Table 3.3.2-5 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
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) 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, 3

Table 3.3.2-5 Plant-Specific Notes:

1. Internal coating: coal tar epoxy.

2. Internal lining: carbon fiber reinforced polymer.

3. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

4. Reduction of heat transfer is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for components with only a pressure boundary function.

5. Material is aluminum-bronze (ASTM B171 Alloy 614) with less than 8% aluminum.

6. The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program is used instead of the Open-Cycle Cooling Water System (B2.1.11) program to manage recurring internal corrosion for internally-coated steel heat exchangers.

7. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

8. Cited GALL item VII.I.A-405a includes “cracking” aging effect that is only applicable for copper alloy (>15% Zn or >8% Al). Cracking is not an applicable aging effect for steel with internal lining components.

Table 3.3.2-6 Auxiliary Systems - Bearing 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	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
Flexible connection	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) 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
Flow restrictor	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
Heat exchanger (bearing cooling - channel)	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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
Heat exchanger (bearing cooling - 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat exchanger (isophase bus duct - header)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat exchanger (isophase bus duct - tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D

Table 3.3.2-6 Auxiliary Systems - Bearing 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
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
Piping, piping components	LB;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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
		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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A, 2
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B, 2

Table 3.3.2-6 Auxiliary Systems - Bearing 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 (bearing 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Pump casing (chemical injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
Pump casing (makeup)	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) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A, 2
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B, 2
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A, 2
Sight 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

Table 3.3.2-6 Auxiliary Systems - Bearing 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
Sight glass (body)	LB	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	B
		Copper alloy (>15% Zn)	(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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
		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
			(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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
Strainer body	LB	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	B
		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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Tank (air conditioner head)	LB;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-202	3.3.1-045	B

Table 3.3.2-6 Auxiliary Systems - Bearing 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 (chemical addition)	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.A-763b	3.3.1-234	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-254	3.3.1-048	B
Tank (chemical injection)	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; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A, 3
Tank (head)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
Valve body	LB;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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A, 1
			(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	B
		Copper alloy (>15% Zn)	(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	B
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A

Table 3.3.2-6 Auxiliary Systems - Bearing 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
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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
		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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A, 2
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B, 2

Table 3.3.2-6 Plant-Specific Notes:

1. Condensation environment applies to gland steam condenser drains.
2. Treated water environment applies to makeup flowpath from the condensate and treated water systems.
3. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for external surfaces or for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-7 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;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
			(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
Filter housing (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
			(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
Heat exchanger (chilled component cooling - 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	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Heat exchanger (chilled component cooling - 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.C2.AP-189	3.3.1-046	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Heat exchanger (chiller - channel)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Heat exchanger (chiller 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
			(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 3.3.2-7 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 (condenser - 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat exchanger (refueling water storage tank - channel)	SI	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D
Heat exchanger (refueling water storage tank - shell)	SI	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	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	A
Piping, piping components	LB	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.C2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-133	3.3.1-099	A

Table 3.3.2-7 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	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	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
			(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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	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-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.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, 1
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B, 1
Pump casing (chilled component cooling)	LB	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A

Table 3.3.2-7 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 circulating)	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	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Sight 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
Sight 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
Tank (chiller oil 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
			(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 (flash)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
Tank (surge)	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	B
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Valve body	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-7 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	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	B
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	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-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.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, 1
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B, 1

Table 3.3.2-7 Plant-Specific Note:

1. Treated water environment is present in the makeup flowpath from the condensate system.

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
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
Expansion joint	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	A
Filter housing	PB	Polymer	(I) Air – dry	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
			(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
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
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-400	3.3.1-127	E, 3
						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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B

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 - tube)	HT;PB	Titanium (ASTM Grade 2)	(E) Closed-cycle cooling water	Cracking; reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.A-767	3.3.1-238	B
			(I) Raw water	Cracking (titanium only); reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	B
Heat exchanger (component cooling - tubesheet)	PB	Steel with titanium cladding	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
			(I) Raw water	Cracking; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-152a	3.3.1-123	B
Heat exchanger (containment penetration jacket)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-770b	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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	D
Heat exchanger (shield penetration jacket)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-770b	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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	D
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	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	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A, 1
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	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
			(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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 4
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A, 2
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B, 2

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)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
Sight glass	LB;PB	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
			(E) Condensation	None	None	VII.J.AP-97	3.3.1-117	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
Sight glass (body)	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
		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	B
Strainer body	LB;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	B
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 4
Tank (air accumulator)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A, 1
			(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 3.3.2-8 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 (charging pump seal cooling surge)	LB;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	B
Tank (chemical addition)	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	B
Tank (surge)	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	B
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, 1
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.A-763b	3.3.1-234	A
		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	B
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	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
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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 4
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	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	B
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 4
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A, 2
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B, 2

Table 3.3.2-8 Plant-Specific Notes:

1. Air-dry environment is for the air supply components to the containment isolation valves for the component cooling supply to the residual heat removal system. Valves fail closed for safety function, but include air tanks to enable opening valves for post-fire operation if normal air supply is not available.

2. Treated water environment is within return line from boron recovery cleanup ion exchangers.

3. TheInternal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program is used instead of the Open-Cycle Cooling Water System (B2.1.11) program to manage recurring internal corrosion for internally-coated carbon steel heat exchangers.

4. Cited GALL item VII.I.A-405a includes "cracking" aging effect that is only applicable for copper alloy (>15% Zn or >8% Al). Cracking is not an applicable aging effect for steel or gray cast iron components.

Table 3.3.2-9 Auxiliary Systems - Neutron Shield Tank 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	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
Heat exchanger (shield tank cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-770b	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	D
Heat exchanger (shield tank cooler - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-770b	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	D
Heat exchanger (shield tank cooler - 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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	B
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	B
Heat exchanger (shield tank cooler - 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	D
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	D
Heat exchanger (shield wall panel)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-770b	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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	D

Table 3.3.2-9 Auxiliary Systems - Neutron Shield Tank 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
		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	B
Tank (corrosion control)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	B
Tank (surge)	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	B

Table 3.3.2-9 Auxiliary Systems - Neutron Shield Tank 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
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
		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	B

Table 3.3.2-9 Plant-Specific Notes: None

Table 3.3.2-10 Auxiliary Systems - Primary Grade 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	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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B

Table 3.3.2-10 Plant-Specific Notes: None

Table 3.3.2-11 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
Blocking device (stored)	FD	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
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	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A

Table 3.3.2-11 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
Filter housing	LB;PB;SI	Polymer	(I) Air – dry	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-797b	3.3.1-263	A, 2
			(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
		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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	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
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C1.AP-127	3.3.1-097	A

Table 3.3.2-11 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
Flexible hose	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Flexible hose (stored)	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	C, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	C, 1
Heat exchanger (air compressor 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
			(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 (air compressor oil tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-133	3.3.1-099	C
					One-Time Inspection (B2.1.20)	VII.C2.AP-133	3.3.1-099	C
Heat exchanger (air compressor seal water channel)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	C

Table 3.3.2-11 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 (air compressor seal water shell)	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	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) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Heat exchanger (air compressor seal water tube)	PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Heat exchanger (air compressor seal water tubesheet)	PB	Copper alloy (>15% Zn)	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	C
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Orifice	LB;PB;RF	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	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	B
					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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	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

Table 3.3.2-11 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
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	(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.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	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	B
		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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C1.AP-127	3.3.1-097	A

Table 3.3.2-11 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
Pump casing (air compressor 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.C1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C1.AP-127	3.3.1-097	A
Sight glass	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
Sight glass (body)	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
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C1.AP-127	3.3.1-097	A
Tank (air compressor moisture 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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A

Table 3.3.2-11 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 (backup air cylinder)	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
Tank (containment air receiver)	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
Tank (stored gas bottle)	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
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Trap body	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Valve body	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
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-11 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
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	None	None	VII.J.AP-144	3.3.1-114	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) 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	(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.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	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	B
		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.D.A-26	3.3.1-055	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.C1.AP-127	3.3.1-097	A

Table 3.3.2-11 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
Valve body (stored)	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

Table 3.3.2-11 Plant-Specific Notes:

1. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
2. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-12 Auxiliary Systems - Primary and Secondary Plant Gas 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 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;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	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
			(I) Treated water	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				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.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	B
Pump casing (steam generator vacuum pump)	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) 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.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	B
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A

Table 3.3.2-12 Auxiliary Systems - Primary and Secondary Plant Gas 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
Strainer body	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	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	B
					Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
Tank (vacuum pump 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.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	B
Valve body	PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	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.C2.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	B

Table 3.3.2-12 Plant-Specific Notes: None

Table 3.3.2-13 Auxiliary Systems - 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	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
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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A

Table 3.3.2-13 Auxiliary Systems - 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
Trap body	LB	Copper alloy (>15% Zn)	(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
		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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Valve body	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.D.AP-221b	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.AP-221c	3.3.1-006	A

Table 3.3.2-13 Plant-Specific Notes: None

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
			(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	B
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				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	B
			(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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (bottoms cooler - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
Heat exchanger (bottoms cooler - 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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat exchanger (distillate cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D
Heat exchanger (distillate cooler - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Heat exchanger (distillate cooler - 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	D
			(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (drain tank pump jacket cooler)	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	B
Heat exchanger (electric heater - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
		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	B
Heat exchanger (evaporator reboiler - channel)	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 reboiler - 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
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	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
Heat exchanger (overhead condenser - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D
Heat exchanger (overhead condenser - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	C, 1
Heat exchanger (overhead 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	D
			(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Heat exchanger (overhead gas compressor - cooling jacket)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (primary drain tank vent chiller condenser - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D
Heat exchanger (primary drain tank vent chiller condenser - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
Heat exchanger (primary drain tank vent chiller 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	D
			(E) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B
Heat exchanger (stripper feed - channel head)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (stripper feed - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B
Heat exchanger (stripper feed - tube and tubesheet)	LB	Stainless steel	(E) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B
Heat exchanger (stripper feed stream heater - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B
Heat exchanger (stripper feed stream heater - 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) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	C
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	D

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (stripper feed stream heater - tube and tubesheet)	LB	Stainless steel	(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B
			(E) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	D
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Heat exchanger (stripper overhead condenser - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D
Heat exchanger (stripper overhead condenser - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B
Heat exchanger (stripper overhead 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	D
			(E) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	D
				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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (stripper trim cooler - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Heat exchanger (stripper trim 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	B
Heat exchanger (stripper trim 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	D
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Orifice	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Piping, piping components	LB;PB;SI	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	B
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				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	B
			(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	B
		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	D
Pump casing (evaporator bottoms cooler)	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-189	3.3.1-046	D
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Pump casing (evaporator bottoms tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 bottoms)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Pump casing (evaporator circulating)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Pump casing (evaporator distillate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
Pump casing (primary drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Pump casing (stripper circulating)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (test tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
Pump casing (waste bottoms)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
			(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	B
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				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	B
			(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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 (boron cleanup ion exchanger)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (cesium removal ion exchanger)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (distillate accumulator)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (evaporator bottoms tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (evaporator tank A - bottoms and tower)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 tank B - bottoms)	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (evaporator tank B - tower)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (gas stripper surge)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (gas stripper)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				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	B
Tank (primary drain tank)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B

Table 3.3.2-14 Auxiliary Systems - Boron Recovery - 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 cylinder)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Valve body	LB;PB;SI	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
			(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.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	B
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				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	B
			(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	B
		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	D

Table 3.3.2-14 Plant-Specific Note:

1. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

Table 3.3.2-15 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Filter housing	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B

Table 3.3.2-15 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
Flow element	LB;PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A, 1
			(I) Treated borated water	None	None	VII.J.AP-52	3.3.1-117	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
			(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	B
Heat exchanger (batch tank jacket heater)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F1.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F1.A-748	3.3.1-219	B
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F1.A-567	3.3.1-170	B
Heat exchanger (charging pump oil cooler - channel)	PB	Copper alloy with internal coating	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A

Table 3.3.2-15 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 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) 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 (charging pump oil cooler - tube)	HT;PB	Copper alloy with internal coating	(E) 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
				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
			(I) Raw water	Cracking (titanium only); reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	B, 3, 4
				Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
Heat exchanger (charging pump oil cooler - tubesheet)	PB	Copper alloy with internal coating	(E) 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
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
Heat exchanger (charging pump seal cooler - case and cover)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	C

Table 3.3.2-15 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 seal cooler - 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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	B
			(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	D
				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	B
Heat exchanger (excess letdown - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
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.E1.AP-189	3.3.1-046	B
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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	B
			(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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
				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	B

Table 3.3.2-15 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	D
			(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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
Heat exchanger (nonregenerative - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
Heat exchanger (nonregenerative - 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	B
Heat exchanger (nonregenerative - 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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	B
			(I) Treated borated water >60°C (>140°F)	Cracking	Water Chemistry (B2.1.2)	VII.E1.A-69	3.3.1-003	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
				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	B

Table 3.3.2-15 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 (nonregenerative - 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	D
			(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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
Heat exchanger (regenerative - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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, 2
					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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
Heat exchanger (regenerative - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D

Table 3.3.2-15 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	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	D
				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	B
			(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, 2
					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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
				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	B
Heat exchanger (regenerative - tubesheet)	PB	Stainless steel	(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	D
			(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, 2
					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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	D
Heat exchanger (seal water - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D

Table 3.3.2-15 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 - 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	B
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	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	B
			(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	D
				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	B
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	D
			(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	D
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 5
						VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	B
			(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	B
				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	B
			(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	B

Table 3.3.2-15 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	(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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
			(E) Concrete	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-425	3.3.1-144	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-137	3.3.1-107	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A
			(E) Soil	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-425	3.3.1-144	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-137	3.3.1-107	A
			(I) Treated borated water	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	None	None	H, 6
				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	B

Table 3.3.2-15 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 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	B
					ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	B, 7, 8
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A, 7, 8
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	B, 7, 8
				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	B
			(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	B
Pump casing (boric acid)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Pump casing (charging pump 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

Table 3.3.2-15 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 (charging)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Pump casing (zinc injection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
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
			(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
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Strainer element	FLT	Stainless steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A
			(E) 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	B

Table 3.3.2-15 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 (boric acid batch)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
				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	B
Tank (boric acid)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (charging pump 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
			(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 (chemical mixing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(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	B
Tank (resin fill)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(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	B

Table 3.3.2-15 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 (volume control)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (zinc addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(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	B
Valve body	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	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	B

Table 3.3.2-15 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	(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	B
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A, 7, 8
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	B, 7, 8
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A, 7
				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	B
			(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	B
		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 3.3.2-15 Plant-Specific Notes:

1. Flow element pressure boundary is alumina ceramic (99.5% Al2O3), chemically the same as ruby and sapphire. This material is considered to be similar to glass for aging evaluations.
2. Unit 2 regenerative heat exchanger tube side is a reactor coolant pressure boundary.
3. Cracking is addressed by the cited NUREG-2191 item for titanium only. It is not an applicable aging effect requiring management for copper alloy.
4. NUREG-2191 item applicability is for copper alloy. In determination of NUREG-2191 consistency for the potential for reduction of heat transfer due to fouling, copper alloy with internal coating is considered an equivalent material to copper alloy.
5. One-time inspection to verify absence of loss of material due to erosion for multistage charging pump miniflow recirculation orifices.
6. Augmented inspections within the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will manage cracking of sensitized stainless steel.
7. Reactor coolant pressure boundary components.
8. Environment is equivalent to reactor coolant for this aging evaluation.

Table 3.3.2-16 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A

Table 3.3.2-16 Plant-Specific Notes: None

Table 3.3.2-17 Auxiliary Systems - Reactor Cavity Purification - 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
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	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	B
Pump casing (purification)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Pump casing (skimmer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B

Table 3.3.2-17 Auxiliary Systems - Reactor Cavity Purification - 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B

Table 3.3.2-17 Plant-Specific Notes: None

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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
Demineralizer shell	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; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A, 1
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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	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; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A, 1
				Loss of material; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(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	B
Flow element	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(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	B
			(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	B
			(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

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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 chiller - shell/channel)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
			(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 - heliflow shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D
		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	B
Heat exchanger (water bath - coils)	LB	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	D
			(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	D
Heat exchanger (water bath - tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(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	B
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	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-221c	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	B
			(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	B
				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	B
			(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	B

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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 borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				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	B
			(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	B
			(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	B
				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	B
			(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
			(I) Treated water	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A, 2
				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	B
Pump casing (flushing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
Pump casing (gas strip evacuating)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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 (high radiation sample waste)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
Pump casing (water bath 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Sample sink	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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, 1
Sight 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
Sight glass (body)	LB	Copper alloy (>15% Zn)	(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	B
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
Tank (high radiation sample waste)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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	(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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C2.AP-221b	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	B
			(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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A, 2
				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	B
			(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	B
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	B
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A, 2
				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	B
			(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	B

Table 3.3.2-18 Auxiliary Systems - Sampling System - 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) 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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A, 2
				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	B
			(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
			(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	B

Table 3.3.2-18 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item in raw water, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

2. Cumulative fatigue TLAA exists for reactor coolant pressure boundary valves only.

Table 3.3.2-19 Auxiliary Systems - Decontamination - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1

Table 3.3.2-19 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-20 Auxiliary Systems - Drains Aerated - 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
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
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; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-728	3.3.1-085	A, 1
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1

Table 3.3.2-20 Auxiliary Systems - Drains Aerated - 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 (auxiliary building sump pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (auxiliary building to turbine building pipe tunnel sump pump)	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) 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
				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
Pump casing (component cooling heat exchanger pit sump pump)	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) 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
				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
Pump casing (containment instrument air compressor room sump pump)	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; 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 3.3.2-20 Auxiliary Systems - Drains Aerated - 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 building sump pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (incore instrumentation room sump pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (reactor containment sump pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (reactor containment sump sample pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (safeguards area sump pump)	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) 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
				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 3.3.2-20 Auxiliary Systems - Drains Aerated - 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 (safeguards valve pit sump pump)	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) 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
				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
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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Tank (primary vent pot)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	C
			(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

Table 3.3.2-20 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-21 Auxiliary Systems - Drains Gaseous - 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
Heat exchanger (primary drain transfer tank cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
Heat exchanger (primary drain transfer tank 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	B
Heat exchanger (primary drain transfer tank cooler - 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	D
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
Heat exchanger (primary drain transfer tank cooler - 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	D
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	D
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B

Table 3.3.2-21 Auxiliary Systems - Drains Gaseous - 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 (primary drain transfer pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
Tank (primary drain transfer tank)	LB	Steel with stainless steel cladding	(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 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	B
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B

Table 3.3.2-21 Plant-Specific Notes: None

Table 3.3.2-22 Auxiliary Systems - Gaseous 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
Blower (waste gas purge)	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)	V.A.E-29	3.2.1-044	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;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
Gas compressor (head)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	D
Heat exchanger (constant temperature bath - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Heat exchanger (recombiner aftercooler - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D

Table 3.3.2-22 Auxiliary Systems - Gaseous 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
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	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)	V.A.E-29	3.2.1-044	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.F3.A-26	3.3.1-055	A
Tank (gas collection)	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-26	3.3.1-055	A

Table 3.3.2-22 Auxiliary Systems - Gaseous 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 (moisture separator)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.I.A-751d	3.3.1-222	A
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	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
			(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)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	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 3.3.2-22 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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;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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Heat exchanger (contaminated drains transfer pumps recirc cooler - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	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	C, 1
Heat exchanger (evaporator - shell, head)	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	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-276	3.3.1-095	A, 1
Heat exchanger (evaporator bottoms cooler - 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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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
Heat exchanger (evaporator bottoms cooler - tube)	LB	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	D
			(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	C, 1
Heat exchanger (evaporator distillate condenser - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	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	D
Heat exchanger (evaporator distillate condenser - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	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
Heat exchanger (evaporator distillate condenser - tube, tubesheet)	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	D
			(E) 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	C, 1
Heat exchanger (evaporator distillate 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	B
Heat exchanger (evaporator distillate cooler - 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	D
			(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	C, 1

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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
Heat exchanger (evaporator reboiler - channel)	LB	Steel with nickel alloy cladding	(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	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-276	3.3.1-095	A, 1
Heat exchanger (evaporator reboiler - tube)	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-770c	3.3.1-241	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-276	3.3.1-095	A, 1
Heat exchanger (evaporator reboiler - tubesheet)	LB	Steel with nickel alloy cladding	(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	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-276	3.3.1-095	A, 1

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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
Piping, piping components	LB;SI	Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Waste water	Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-551	3.3.1-175	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	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
Pump casing (contaminated drains transfer pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (distillate pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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 (high level waste drain pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (laboratory waste drain tank pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (low level waste drain pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (waste disposal evaporator bottoms cooler pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (waste disposal evaporator bottoms pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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 (waste disposal evaporator circulating pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Pump casing (waste disposal evaporator test tank pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1
Tank (contaminated drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Tank (distillate tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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 (high level waste drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Tank (laboratory waste drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Tank (liquid waste evaporator test tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Tank (low level waste drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Tank (spent resin blend)	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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

Table 3.3.2-23 Auxiliary Systems - Liquid and Solid 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 (spent resin catch)	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Tank (waste disposal evaporator distillate demineralizer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Tank (waste disposal test tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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
Valve body	LB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	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 3.3.2-23 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-24 Auxiliary Systems - Plumbing - 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) 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
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) Waste water	Flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-780	3.3.1-258	A
				Hardening or loss of strength; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-728	3.3.1-085	A
Grating (storm drain)	FLT	Gray cast iron	(E) Air – outdoor	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	Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Waste water	Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-551	3.3.1-175	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
			(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.A-400	3.3.1-127	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
		PVC	(E) Waste water	Loss of material; flow blockage	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-787d	3.3.1-253	E, 3
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-787d	3.3.1-253	A

Table 3.3.2-24 Auxiliary Systems - Plumbing - 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) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C
			(I) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C, 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) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	C, 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
Piping, piping components (storm drain)	FD	Polymer	(I) Raw water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-797b	3.3.1-263	A, 4
Pump casing (containment sub-surface drain pump)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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
Pump casing (drain pump - service building)	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) 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
				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
Pump casing (sewage ejection transfer pump)	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) 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
				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 3.3.2-24 Auxiliary Systems - Plumbing - 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 pump - Amertap pit)	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) 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
				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
Pump casing (sump pump - ductline)	PB	Gray cast iron	(E) Waste water	Loss of material	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
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	C, 2
Pump casing (sump pump - electrical manhole)	LB	Stainless steel	(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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C, 2
Pump casing (sump pump - turbine building)	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) 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
				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
Pump casing (turbine building sub-surface drain pump)	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) 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
				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 3.3.2-24 Auxiliary Systems - Plumbing - 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 (air and vacuum sewer valve tank)	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) 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
Tank (sewage tank)	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) 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
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	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-272	3.3.1-095	A, 1
		Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Waste water	Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-551	3.3.1-175	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
			(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
				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
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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, 1

Table 3.3.2-24 Auxiliary Systems - Plumbing - 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) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	C
			(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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	C, 2

Table 3.3.2-24 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

2. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

3. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for external surfaces.

4. The function of storm drain piping is to remove water from the yard. The only applicable aging effect is flow blockage, as piping integrity is not required.

Table 3.3.2-25 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
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
Filter housing	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
Flow element	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
Piping, piping components	PB;SI	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
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A

Table 3.3.2-25 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
Pump casing (particulate and gas sampler air pump)	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
Radiation sampler	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A
Valve body	PB;SI	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
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	3.3.1-006	A

Table 3.3.2-25 Plant-Specific Notes: None

Table 3.3.2-26 Auxiliary Systems - Vents Aerated - 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
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E1.AP-221c	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)	V.A.E-29	3.2.1-044	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.F3.A-26	3.3.1-055	A
Tank (knockout drum)	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-26	3.3.1-055	A

Table 3.3.2-26 Auxiliary Systems - Vents Aerated - 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	(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)	V.A.E-29	3.2.1-044	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.F3.A-26	3.3.1-055	A

Table 3.3.2-26 Plant-Specific Notes: None

Table 3.3.2-27 Auxiliary Systems - Vents Gaseous - 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
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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	B
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Valve body	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-27 Plant-Specific Notes: None

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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
Demineralizer (flash evaporator - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Filter housing (chiller supply)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.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
Filter housing (demineralizer postfilter)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
Filter housing (demineralizer prefilter)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
Filter housing (laboratory tank vent filter)	LB	Copper alloy (>15% Zn)	(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	B
					Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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 (laboratory water filter)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
Filter housing (water heater supply)	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.H2.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, 1
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; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A, 1
				Loss of material; flow blockage (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A, 1

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) 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, 1
			(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	B
		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.H2.A-439	3.3.1-193	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	B
Heat exchanger (flash evaporator - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-770b	3.3.1-241	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	D
Orifice	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.H2.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, 1
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-439	3.3.1-193	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	B
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

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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	Fiberglass	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Treated water	Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-644	3.3.1-175	A, 1
			(I) Waste water	Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-551	3.3.1-175	A, 1
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
			(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

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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	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.H2.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, 1
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-439	3.3.1-193	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	B
			(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
		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) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-414	3.3.1-139	A
Pump casing (chemical addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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 (chemical metering)	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; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 1
Pump casing (clean water booster)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
Pump casing (condensate polisher regeneration)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
Pump casing (cyclohexylamine)	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.H2.A-439	3.3.1-193	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	B
Pump casing (demineralizer waste sump)	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	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-279	3.3.1-095	A, 1

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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 (flash evaporator distillate)	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.H2.A-439	3.3.1-193	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	B
Pump casing (flash evaporator makeup)	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) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.H2.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, 1
Pump casing (flash evaporator recycle)	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.H2.A-439	3.3.1-193	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	B
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
		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.H2.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.H2.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, 1
Pump casing (phosphate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.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
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	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	B
		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.H2.A-439	3.3.1-193	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	B
Tank (air chamber)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.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
		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.H2.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, 1

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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 (ammonia hydroxide)	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; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 1
Tank (chemical addition)	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.H2.A-439	3.3.1-193	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	B
Tank (cyclohexylamine)	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.H2.A-439	3.3.1-193	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	B
Tank (head)	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.H2.A-439	3.3.1-193	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	B
Tank (hot water)	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.H2.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, 1

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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 (laboratory demineralizer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
Tank (make-up pump head)	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.H2.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, 1
Tank (phosphate)	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.H2.A-439	3.3.1-193	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	B
Tank (relief)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	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	B
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
			(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	B

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.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
			(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	B
					Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	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
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.H2.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, 1
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-439	3.3.1-193	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	B
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	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
				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
		Gray cast 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
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-414	3.3.1-139	A
						VII.G.A-415	3.3.1-140	A

Table 3.3.2-28 Auxiliary Systems - Water Treatment - 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	PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) 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, 1
			(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	B
			(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) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.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, 1
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-439	3.3.1-193	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	B
			(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 3.3.2-28 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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 (fin)	HT	Copper alloy	(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-565	3.3.1-161	C
Air handling unit (header)	LB;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	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Air handling unit (housing)	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
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-08	3.3.1-090	A
Air handling unit (nonsafety-relate d tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
			(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	B
Air handling unit (safety-related tube)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-565	3.3.1-161	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

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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 (HVAC)	PB;SI	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 – outdoor	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
Compressor (chiller gas)	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) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Cooling coils (containment air recirculation - 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	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Cooling coils (containment air recirculation - fin)	HT	Copper alloy	(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-565	3.3.1-161	C
Cooling coils (containment air recirculation - housing)	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
			(E) Condensation	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.F1.A-08	3.3.1-090	A
Cooling coils (containment air recirculation - tube)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-565	3.3.1-161	A

Table 3.3.2-29 Auxiliary Systems - Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Cooling coils (reactor shroud - 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	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Cooling coils (reactor shroud - fin)	HT	Copper alloy	(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-565	3.3.1-161	C
Cooling coils (reactor shroud - housing)	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
			(E) Condensation	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.F1.A-08	3.3.1-090	A
Cooling coils (reactor shroud - tube)	HT;PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-565	3.3.1-161	A
Damper housing	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Drip pan	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.AP-221c	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-781c	3.3.1-094a	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.AP-99c	3.3.1-094	A

Table 3.3.2-29 Auxiliary Systems - Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Ducting	FB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-781b	3.3.1-094a	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-99b	3.3.1-094	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-781b	3.3.1-094a	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-99b	3.3.1-094	C, 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
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 2
			(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) 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
Fan housing	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 2
			(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	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 2
			(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 3.3.2-29 Auxiliary Systems - Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fire damper (housing)	FB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material; cracking; hardening; loss of strength; shrinkage	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A, 3
			(I) Air – indoor uncontrolled	Loss of material; cracking; hardening; loss of strength; shrinkage	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A, 3
			(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
Flexible connection	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	C, 2
Flexible hose (Appendix R temporary ducting)	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	C, 2
Heat exchanger (central chilled water condenser - shell)	LB	Steel	(E) Condensation	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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 (central chilled water evaporator - shell)	LB	Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
			(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 (control room chilled water condenser - channel)	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
			(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	B
Heat exchanger (control room chilled water condenser - shell)	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
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (control room chilled water condenser - tube)	HT;PB	Copper alloy	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
			(I) Raw water	Cracking (titanium only); reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	B
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-400	3.3.1-127	B
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-179	3.3.1-038	D
		Copper alloy with internal coating	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
			(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 (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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 (control room chilled water condenser - tubesheet)	PB	Steel with internal coating	(E) Gas	None	None	VII.J.AP-6	3.3.1-121	C
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
Heat exchanger (control room chilled water evaporator - channel)	PB	Gray cast iron	(E) Condensation	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	C
Heat exchanger (control room chilled water evaporator - shell)	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	B
			(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 (control room chilled water evaporator - tube)	HT;PB	Copper alloy	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	C
Heat exchanger (control room 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	B
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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	(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.F3.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-221b	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	A
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) 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
			(I) 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, 1
		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; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-797b	3.3.1-263	A, 1

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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) 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.F3.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.AP-221c	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
		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	B
			(E) Condensation	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
Pump casing (central chilled water pump)	LB	Gray cast iron	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	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 (chiller oil)	LB;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.F1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F1.AP-127	3.3.1-097	A

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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 (control room chilled water)	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	A
Pump casing (control room chiller service water)	PB	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	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	B
Strainer body	LB;PB	Stainless steel	(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	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	B
		Steel	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(E) Condensation	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	B
Strainer element	FLT	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	B
			(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B, 1

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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 (air bottle)	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
Tank (control room chilled water surge)	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
Tank (control room chilled water surge - bladder)	PB	Elastomer	(E) 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
			(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
Valve body	LB;PB	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-47	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, 1
			(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
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A

Table 3.3.2-29 Auxiliary Systems - Ventilation - 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	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; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-797b	3.3.1-263	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.AP-221c	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	B
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-734c	3.3.1-205	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-761c	3.3.1-232	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	B
			(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 Auxiliary Systems - Ventilation - 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)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 2
			(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	B
			(E) Condensation	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

Table 3.3.2-29 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow, or for strainer elements that are monitored for clogging.

2. Internal and external environments of these ventilation components are such that the external surface condition is representative of the internal surface condition.

3. This row is applicable to fire dampers. Cracking, hardening and loss of strength, and shrinkage are not aging effects requiring management for steel fire dampers exposed to indoor air.

Table 3.3.2-30 Auxiliary Systems - Leakage 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
Bolting	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 housing	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.A-763b	3.3.1-234	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	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-209b	3.3.1-004	C, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-221b	3.3.1-006	C, 1
Valve body	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-209b	3.3.1-004	C, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F3.AP-221b	3.3.1-006	C, 1

Table 3.3.2-30 Plant-Specific Note:

1. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

Table 3.3.2-31 Auxiliary Systems - Secondary Vents - 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;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 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	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
		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) 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 3.3.2-31 Plant-Specific Notes: None

Table 3.3.2-32 Auxiliary Systems - Vacuum Priming - 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	Copper alloy	(E) Air – indoor uncontrolled	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
Heat exchanger (seal water - channel)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	C
Heat exchanger (seal water - shell)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	D
					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) 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	B
		Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	C, 2
			(I) Raw water	Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-460	3.3.1-175	A, 1

Table 3.3.2-32 Auxiliary Systems - Vacuum Priming - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-221c	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-221c	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-26	3.3.1-055	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, 1
Pump casing (seal water)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Pump casing (vacuum priming)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A

Table 3.3.2-32 Auxiliary Systems - Vacuum Priming - 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	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	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) 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, 1
Strainer body	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Tank (offtake)	LB	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
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
Tank (separator)	LB	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
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A

Table 3.3.2-32 Auxiliary Systems - Vacuum Priming - 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 (vacuum priming)	LB	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
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C1.A-414	3.3.1-139	A
Valve body	LB;PB;SI	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
			(I) 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, 1
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-47	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, 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	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, 1

Table 3.3.2-32 Auxiliary Systems - Vacuum Priming - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-221c	3.3.1-006	A
			(I) 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, 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) 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, 1

Table 3.3.2-32 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

2. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

Table 3.3.2-33 Auxiliary Systems - Containment Vacuum - 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
Piping, piping components	LB;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 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.F3.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F3.A-566	3.3.1-169	B
Tank (vacuum pump)	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 with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Vacuum ejector	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) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F3.A-566	3.3.1-169	B
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 with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-33 Plant-Specific Notes: None

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	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
Compressor housing (hydropneumatic tank)	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	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
Drip pan and enclosures (reactor coolant pump oil collection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-221b	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.G.AP-138	3.3.1-100	A
Exhaust silencer	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-221b	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
Expansion joint	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-221b	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage (raw water only)	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B

Table 3.3.2-34 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fire hydrant	PB	Gray cast iron	(E) Air – outdoor	Loss of material; flow blockage (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	B, 3
			(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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	B
			(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 (B2.1.27)	VII.I.AP-198	3.3.1-109	A
Flame arrestor	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-221b	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.G.AP-138	3.3.1-100	A
Flexible connector	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-221b	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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.G.AP-138	3.3.1-100	A

Table 3.3.2-34 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Hose rack (fittings)	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
			(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
				Loss of material; flow blockage (raw water only)	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Nozzle	SP	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
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 2
Odorizer	PB	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
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Orifice	PB;RF	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.G.A-532	3.3.1-193	A
				Loss of material; flow blockage (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Piping, piping components	PB	Copper alloy	(E) Air – indoor uncontrolled	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	B
					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
		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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	B

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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	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) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	B
			(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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
		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 (B2.1.28)	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 (B2.1.28)	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 (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-221b	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
				Cumulative fatigue damage	TLAA	VII.E1.A-57	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.G.AP-138	3.3.1-100	A

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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	Steel	(E) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 5
					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	B
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 5
			(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) Raw water	Cracking	TLAA	None	None	H, 6
				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-400	3.3.1-127	B
				Loss of material; flow blockage (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Pump casing (diesel fuel)	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.G.AP-234a	3.3.1-070	B
Pump casing (fire pump)	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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Pump casing (pressure maintenance)	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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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	PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A
Sight glass (reactor coolant pump oil collection - plexiglass)	PB	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) 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	C, 1
Sight glass 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) 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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Sprinkler head	SP	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B, 3
			(I) Air – indoor uncontrolled	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B
			(E) Air – outdoor	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B, 3
			(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
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B
Strainer 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) 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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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 (deluge/alarm check trim)	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 (raw water only)	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Strainer element	FLT	Steel	(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; flow blockage (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Strainer element (deluge/alarm check trim)	FLT	Stainless steel	(E) Raw water	Loss of material; flow blockage (raw water only)	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B
Tank (carbon dioxide)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	C
			(E) Air – outdoor	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	C
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (fire protection and domestic water storage)	PB	Steel with internal coating	(E) Air – outdoor	Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	B
			(E) Soil	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VII.H1.A-401	3.3.1-128	B
			(I) Raw water	Loss of coating or lining integrity	Fire Water System (B2.1.16)	VII.G.A-416	3.3.1-138	E, 4
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-414	3.3.1-139	E, 4
Tank (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.G.AP-234a	3.3.1-070	B
Tank (halon)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	C
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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 (hydropneumatic)	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) 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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Tank (reactor coolant pump oil collection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.G.AP-138	3.3.1-100	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
		Gray cast iron	(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(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	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
			(E) Air – outdoor	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	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) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
				Loss of material; flow blockage (raw water only)	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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	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) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(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) 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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
			(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 (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.G.AP-221b	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.G.AP-138	3.3.1-100	A
			(I) Raw water	Loss of material; flow blockage (raw water only)	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B

Table 3.3.2-34 Auxiliary Systems - Fire Protection - 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)	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	B
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 5
			(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) 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 (raw water, raw water (potable) only)	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-34 Plant-Specific Notes:

1. Visual inspection from the external surface of plexiglass windows of the reactor coolant pump oil collection enclosures can identify both internal and external degradation of the plexiglass.
2. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
3. Flow blockage is not an applicable aging effect in this environment, or for external surfaces.
4. The Fire Water System (B2.1.16) program is used instead of the Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program to manage loss of material for internally coated carbon steel fire water storage tanks. The Fire Water System (B2.1.16) program manages degraded internal coatings consistent with NUREG-2191 Table XI.M27-1 note 4.
5. The Fire Protection (B2.1.15) program will manage aging of the external surfaces of carbon dioxide and halon system piping components.
6. Fatigue cracking of fire protection piping defects is a TLAA, evaluated in Section 4.7.5, Piping Subsurface Flaw Evaluations.

Table 3.3.2-35 Auxiliary Systems - Hydrogen Gas - 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) 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
Heat exchanger (carbon dioxide vaporizer - channel / tubesheet)	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) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	D
Heat exchanger (carbon dioxide vaporizer - tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	D
Heat exchanger (gas dryer - 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Piping, piping components	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) Gas	None	None	VII.J.AP-6	3.3.1-121	A, 1
			(I) Waste water	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, 2
Tank (moisture 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
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Tank (water detector)	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) Gas	None	None	VII.J.AP-6	3.3.1-121	A, 1

Table 3.3.2-35 Auxiliary Systems - Hydrogen Gas - 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	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) Waste water	Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	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, 2
Valve body	LB;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) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A, 1

Table 3.3.2-35 Plant-Specific Notes:

1. Component function is to provide a leakage boundary in the event of a generator hydrogen cooler leak. However, the expected environment is hydrogen (gas).

2. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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 dryer	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) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-797b	3.3.1-263	A, 5
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) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	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
Drip pan	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) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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	LB;PB	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	C, 3, 4
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	C, 3, 4
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-451c	3.3.1-189	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-763c	3.3.1-234	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-162	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-162	3.3.1-099	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) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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	(I) Air – dry	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-504	3.3.1-085	A
				Loss of material; flow blockage (raw water, waste water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.AP-103	3.3.1-096	A, 5
			(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) Fuel oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H1.A-660	3.3.1-085	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	3.3.1-006	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
Heat exchanger (aftercooler - channel)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat exchanger (aftercooler - fin)	HT	Aluminum	(E) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-788c	3.3.1-254	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-771c	3.3.1-242	A, 1
				Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-419	3.3.1-096a	C, 1

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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 (aftercooler - shell)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	C
Heat exchanger (aftercooler - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-419	3.3.1-096a	A, 1
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	D, 1
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B, 1
Heat exchanger (aftercooler - tubesheet)	PB	Steel	(E) 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat exchanger (air start aftercooler - tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	C
Heat exchanger (immersion heater)	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	B
Heat exchanger (lube oil - channel)	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	B
			(E) 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 (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
Heat exchanger (radiator - header)	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-203	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	C

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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 (radiator - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
Lubricator body	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	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
Motor casing (air start motor)	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	A
Orifice	PB;RF	Copper alloy (>15% Zn)	(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) 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
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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) 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.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-221c	3.3.1-006	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-221c	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	B
					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
			(E) Soil	Cracking (steel in carbonate/bicarbonate environment only)	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-425	3.3.1-144	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-137	3.3.1-107	A

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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	(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.F4.A-778	3.3.1-249	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	B
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
Pump casing (fuel 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) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Pump casing (fuel tank level bubbler hand pump)	PB	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	A, 4
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	A, 4
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	C, 3, 4
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	C, 3, 4
Pump casing (jacket cooling)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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 (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
Rupture disc	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	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	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-136	3.3.1-071	A
Sight glass	PB	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
			(I) Fuel oil	None	None	VII.J.AP-49	3.3.1-117	A
			(I) Lubricating oil	None	None	VII.J.AP-15	3.3.1-117	A
Sight glass (body)	PB	Copper alloy (>15% Zn)	(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	B
					Selective Leaching (B2.1.21)	VII.C2.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	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	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.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Silencer (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) 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

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-129	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-129	3.3.1-071	A
		Copper alloy (>15% Zn)	(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.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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
		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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	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) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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	Nickel alloy	(E) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	None	None	G, 2
					One-Time Inspection (B2.1.20)	None	None	G, 2
		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	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-136	3.3.1-071	A
		Steel	(E) 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 (fuel oil, auxiliary)	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	B
Tank (fuel oil, 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) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Tank (fuel oil, buried)	PB	Steel	(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
Tank (jacket cooling 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	B
Tank (starting 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-751c	3.3.1-222	A
Turbocharger housing (compressor)	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) 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

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Turbocharger housing (turbine)	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) 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
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	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	B
					Selective Leaching (B2.1.21)	VII.C2.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	B
					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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-221c	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	B
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-221c	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	B
					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

Table 3.3.2-36 Auxiliary Systems - Emergency Diesel Generator System - 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	(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.F4.A-778	3.3.1-249	C
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-36 Plant-Specific Notes:

1. Visual inspections of fins and finned tubes will identify fouling, corrosion product buildup or missing fins.
2. The Fuel Oil Chemistry (B2.1.18) program will manage loss of material by precluding the presence of water, and theOne-Time Inspection (B2.1.20) program will confirm the effectiveness of the Fuel Oil Chemistry (B2.1.18) program.
3. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
4. Fuel tank level bubbler hand pump and filter housing not shown on drawings.
5. Flow blockage is not an applicable aging effect in this environment, or for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-37 Auxiliary Systems - Alternate AC - 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 – 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
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.F4.A-504	3.3.1-085	A
				Loss of material; flow blockage (raw water, waste water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.AP-103	3.3.1-096	A, 3
			(E) Air – outdoor	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
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	3.3.1-006	A
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	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 3.3.2-37 Auxiliary Systems - Alternate AC - 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	PB	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	None	None	VII.J.AP-144	3.3.1-114	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.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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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 housing (head)	PB	Copper alloy (>15% Zn)	(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.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A

Table 3.3.2-37 Auxiliary Systems - Alternate AC - 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	(I) Air – dry	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-504	3.3.1-085	A
				Loss of material; flow blockage (raw water, waste water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.AP-103	3.3.1-096	A, 3
			(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) Condensation	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-504	3.3.1-085	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-221c	3.3.1-006	A
Heat exchanger (aftercooler - channel)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	C
Heat exchanger (aftercooler - shell)	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) 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
Heat exchanger (aftercooler - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-419	3.3.1-096a	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B

Table 3.3.2-37 Auxiliary Systems - Alternate AC - 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 (aftercooler - 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	B
Heat exchanger (cooling water and fuel oil radiators - fin)	HT	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F4.A-788b	3.3.1-254	A, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F4.A-771b	3.3.1-242	A, 1
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	C, 1
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F4.A-788b	3.3.1-254	A, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F4.A-771b	3.3.1-242	A, 1
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	C, 1
Heat exchanger (cooling water and fuel oil radiators - header)	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 – 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.C2.AP-189	3.3.1-046	B
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B

Table 3.3.2-37 Auxiliary Systems - Alternate AC - 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 (cooling water and fuel oil radiators - tube)	HT;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, 1
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A, 1
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A, 1
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A, 1
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F4.AP-204	3.3.1-050	B
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Heat exchanger (lube oil - 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
			(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 (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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	B
Heat exchanger (lube oil - tube)	HT;PB	Copper alloy	(E) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
			(I) 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
Heat exchanger (lube oil - 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	B
			(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 3.3.2-37 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heater housing (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.C2.AP-189	3.3.1-046	B
Heater housing (lubricating 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-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A
Lubricator body	PB	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	None	None	VII.J.AP-144	3.3.1-114	A
Motor casing (air start motor)	PB	Gray cast iron	(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
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	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	B
Piping, piping components	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-221c	3.3.1-006	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

Table 3.3.2-37 Auxiliary Systems - Alternate AC - 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	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.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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	B
			(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	B
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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 (fuel transfer)	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) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Pump casing (jacket water)	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	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
Sight glass	PB	Glass	(E) Air – outdoor	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

Table 3.3.2-37 Auxiliary Systems - Alternate AC - 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)	PB	Copper alloy (>15% Zn)	(E) Air – outdoor	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
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
Tank (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	B
Tank (fuel rack shutoff air tank)	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
Tank (jacket water expansion)	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
			(I) Closed-cycle cooling water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VII.C2.A-414	3.3.1-139	A
Tank (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
			(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 3.3.2-37 Auxiliary Systems - Alternate AC - 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 (start air receiver)	PB	Steel with internal coating	(I) Air – dry	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	None	None	G, 2
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	None	None	G, 2
			(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
Turbocharger (compressor)	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) 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
Turbocharger (turbine)	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) 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
Valve body	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.A-763b	3.3.1-234	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-451c	3.3.1-189	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-763c	3.3.1-234	A
		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 3.3.2-37 Auxiliary Systems - Alternate AC - 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	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	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
			(E) Air – outdoor	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	B
					Selective Leaching (B2.1.21)	VII.C2.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	B
					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
		Gray cast iron	(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	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	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 3.3.2-37 Auxiliary Systems - Alternate AC - 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	(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.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-209c	3.3.1-004	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-221c	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	B
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-136	3.3.1-071	B
					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
		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.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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	B
			(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.H2.AP-105a	3.3.1-070	B
			(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 3.3.2-37 Plant-Specific Notes:

1. External visual inspections of fins and finned tubes will identify fouling, corrosion product buildup or missing fins.

2. Internal epoxy coating provides barrier for internal steel surface. The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will manage aging of the coating.

3. Flow blockage is not an applicable aging effect in this environment.

Table 3.3.2-38 Auxiliary Systems - Security - 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
Filter housing (intake air)	PB	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) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-797b	3.3.1-263	A
Flexible connection (radiator exhaust)	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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	C, 2

Table 3.3.2-38 Auxiliary Systems - Security - 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) 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	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	C, 2
			(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) Fuel oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H1.A-660	3.3.1-085	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.H2.AP-221b	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
Heat exchanger (lube oil - channel)	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	B
			(E) 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 (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 3.3.2-38 Auxiliary Systems - Security - 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	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
			(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
Heat exchanger (lube oil - tubesheet)	PB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	D
			(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
Heat exchanger (radiator fin)	HT	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F4.A-788b	3.3.1-254	A, 1
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F4.A-771b	3.3.1-242	A, 1
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	C, 1
Heat exchanger (radiator header)	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	B
Heat exchanger (radiator tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A, 1
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	D
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	B
Heater housing (coolant)	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	B

Table 3.3.2-38 Auxiliary Systems - Security - 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	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	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.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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-202	3.3.1-045	B
			(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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(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 (coolant)	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	B
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	B
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

Table 3.3.2-38 Auxiliary Systems - Security - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Silencer	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
Tank (coolant)	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	B
Tank (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	B
Turbocharger (compressor)	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.F4.A-778	3.3.1-249	C
Turbocharger (turbine)	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
Valve body	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A

Table 3.3.2-38 Plant-Specific Notes:

1. External visual inspections of fins and finned tubes will identify fouling, corrosion product buildup or missing fins.
2. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

Table 3.3.2-39 Auxiliary Systems - Buildings and Structures - 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
Piping, piping components	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)	V.A.E-29	3.2.1-044	A
Valve 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)	V.A.E-29	3.2.1-044	A

Table 3.3.2-39 Plant-Specific Notes: None

Table 3.3.2-40 Auxiliary Systems - Containment Access - 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
Door actuator body (hydraulic drive)	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, 1
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A, 1
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A, 1
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A, 1
Pump casing (personnel hatch hand pump)	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, 1
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A, 1

Table 3.3.2-40 Auxiliary Systems - Containment Access - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E1.AP-221b	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A, 1
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A, 1
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A, 1

Table 3.3.2-40 Plant-Specific Note:

1. Hydraulic fluid is a high grade mineral base oil such as SOHIVIS 43 that is similar to lubricating oils for which aging management is primarily by verification of exclusion of water.

Table 3.3.2-41 Auxiliary Systems - Electrical Power - 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
Heat exchanger (exciter air cooler - 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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-189	3.3.1-046	B
Heat exchanger (exciter air cooler - tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-203	3.3.1-046	B

Table 3.3.2-41 Plant-Specific Notes: None

Table 3.3.2-42 Auxiliary Systems - Helium Vacuum Drying - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B
Pump casing (dry shielded canister reflood pump)	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-763b	3.3.1-234	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-130	3.3.1-025	A
					Water Chemistry (B2.1.2)	VII.C2.AP-130	3.3.1-025	B
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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	B

Table 3.3.2-42 Plant-Specific Notes: None

Table 3.3.2-43 Auxiliary Systems - Reactor Building Penetrations - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Valve body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	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 3.3.2-43 Plant-Specific Notes: None

Tables 3.3.2-1 through 3.3.2-43 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.

Intentionally Blank

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.

- Main Turbine (Section 2.3.4.1)
- Electro-Hydraulic Control (Section 2.3.4.2)
- Lubricating Oil (Section 2.3.4.3)
- Main Steam (Section 2.3.4.4)
- Heating (Section 2.3.4.5)
- Extraction Steam (Section 2.3.4.6)
- Auxiliary Steam (Section 2.3.4.7)
- Feedwater (Section 2.3.4.8)
- Condensate (Section 2.3.4.9)
- Condensate Polishing (Section 2.3.4.10)
- Steam Drains (Section 2.3.4.11)
- Blowdown (Section 2.3.4.12)
- Steam Generator Recirculation and Transfer (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 - Main Turbine - Aging Management Evaluation
- Table 3.4.2-2, Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation
- Table 3.4.2-3, Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation
- Table 3.4.2-4, Steam and Power Conversion System - Main Steam - Aging Management Evaluation
- Table 3.4.2-5, Steam and Power Conversion System - Heating - Aging Management Evaluation
- Table 3.4.2-6, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation
- Table 3.4.2-7, Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation
- Table 3.4.2-8, Steam and Power Conversion System - Feedwater - Aging Management Evaluation
- Table 3.4.2-9, Steam and Power Conversion System - Condensate - Aging Management Evaluation
- Table 3.4.2-10, Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation
- Table 3.4.2-11, Steam and Power Conversion System - Steam Drains - Aging Management Evaluation
- Table 3.4.2-12, Steam and Power Conversion System - Blowdown - Aging Management Evaluation
- Table 3.4.2-13, Steam and Power Conversion System - Steam Generator Recirculation and Transfer - Aging Management Evaluation

3.4.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.4.2.1.1 Main Turbine System

Materials

The materials of construction for the main turbine system component types are:

- Stainless steel
- Steel

Environment

The main turbine system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Steam

Aging Effects Requiring Management

The following aging effects, associated with the main turbine system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the main turbine system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.2 Electro-Hydraulic Control System

Materials

The materials of construction for the electro-hydraulic control system component types are:

- Copper alloy
- Copper alloy (>15 percent Zn)
- Elastomer
- Gray cast iron
- Stainless steel
- Steel

Environment

The electro-hydraulic control system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Gas
- Lubricating oil

Aging Effects Requiring Management

The following aging effects, associated with the electro-hydraulic control 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 electro-hydraulic control system component types:

- Bolting Integrity (B2.1.9)
- 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)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.4.2.1.3 Lubricating Oil System

Materials

The materials of construction for the lubricating oil system component types are:

- Copper alloy (>15 percent Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The lubricating oil system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Lubricating oil
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the lubricating oil 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 lubricating oil system component types:

- Bolting Integrity (B2.1.9)
- 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)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.4.2.1.4 Main Steam System

Materials

The materials of construction for the main steam system component types are:

- Copper alloy
- Stainless steel
- Steel

Environment

The main steam system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation
- Steam
- Treated water

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
- 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)
- 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)

3.4.2.1.5 Heating System

Materials

The materials of construction for the heating system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15 percent Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The heating system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Concrete
- Fuel oil
- Raw water
- Steam
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the heating system, require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- 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 heating system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Fuel Oil Chemistry (B2.1.18)
- 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)

3.4.2.1.6 Extraction Steam System

Materials

The materials of construction for the extraction steam system component types are:

- Copper alloy
- Nickel alloy
- Stainless steel
- Steel

Environment

The extraction steam 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 extraction steam 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 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)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.7 Auxiliary Steam System

Materials

The materials of construction for the auxiliary steam system component types are:

- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The auxiliary steam system component types are exposed to the following environments:

- 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 auxiliary steam system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary steam 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)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.8 Feedwater System

Materials

The materials of construction for the feedwater system component types are:

- Copper alloy
- Copper alloy (>15 percent Zn)
- Ductile iron
- Elastomer
- Glass
- Gray cast iron
- Polymer
- 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
- Closed-cycle cooling water
- Concrete
- Condensation
- Lubricating oil
- Soil
- Steam
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the feedwater 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
- 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)
- Buried and Underground Piping and Tanks (B2.1.27)
- 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)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.9 Condensate System

Materials

The materials of construction for the condensate system component types are:

- Copper alloy
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The condensate system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Closed-cycle cooling water
- Concrete
- Lubricating oil
- Soil
- Treated water
- Treated water >60°C (>140°F)
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the condensate system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the condensate system component types:

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- 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 (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.10 Condensate Polishing System

Materials

The materials of construction for the condensate polishing system component types are:

- Copper alloy
- Fiberglass
- Stainless steel
- Steel
- Steel with internal lining

Environment

The condensate polishing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the condensate polishing system, require management:

- Cracking
- Cracking, blistering, loss of material
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the condensate polishing system component types:

- Bolting Integrity (B2.1.9)
- 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 (B2.1.28)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.11 Steam Drains System

Materials

The materials of construction for the steam drains system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15 percent Zn)
- Glass
- Gray cast iron
- Nickel alloy
- Stainless steel
- Steel

Environment

The steam drains system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed-cycle cooling water
- Condensation
- Lubricating oil
- Steam
- Treated water
- Treated water >60°C (>140°F)
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the steam drains system, require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- 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 steam drains system component types:

- Bolting Integrity (B2.1.9)
- 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)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.12 Blowdown System

Materials

The materials of construction for the blowdown system component types are:

- Nickel alloy
- Stainless steel
- Steel

Environment

The 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 blowdown 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 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)
- Steam Generators (B2.1.10)
- Water Chemistry (B2.1.2)

3.4.2.1.13 Steam Generator Recirculation and Transfer System

Materials

The materials of construction for the steam generator recirculation and transfer system component types are:

- Stainless steel
- Steel

Environment

The steam generator recirculation and transfer system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed-cycle cooling water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the steam generator recirculation and transfer 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 steam generator recirculation and transfer 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)
- 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 4.3.3, Metal Fatigue – ANSI B31.1.

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.

Cracking due to stress corrosion cracking is an aging effect requiring management for stainless steel components exposed to air or condensation in the Steam and Power Conversion Systems for SPS.

Operating experience has confirmed that cracking of the external surfaces of stainless steel components in indoor air has occurred. Cracking was found at SPS and was attributed to chloride induced transgranular stress corrosion cracking. Cracking has been identified on the external surfaces of stainless steel heat exchangers, piping, and welds in the residual heat removal system in the Containment buildings, as well as on safety injection instrument piping in the Unit 2 Safeguards building.

Cracking of a SPS Unit 2 small bore residual heat removal balance line was identified in 2002. The source of chloride contamination at this location was not determined. Cracking was found at the Unit 1 residual heat removal heat exchangers in 2007 and at the Unit 2 residual heat removal heat exchangers in 2010.

The exact source of chloride contamination of the residual heat removal surfaces is unknown. Chloride contamination most likely originated from the insulation, although a review of the original insulation specification identified that requirements did exist when installing insulation on austenitic stainless steel to minimize the possibility of chlorides leaching from the insulation. In addition to repair of the damaged areas, the insulation was removed and the surfaces were cleaned and verified to be free of detectable chlorides.

Cracking of an uninsulated SPS Unit 2 low-head safety injection discharge flow element sensing line was identified in 2004. The cause was determined to be chloride induced stress corrosion cracking from the outside diameter. The apparent source of contamination was rainwater leakage into the valve pits housing the piping. Corrective actions included replacement of the affected piping and performing inspections of similar piping to identify any additional cracking (none was found).

Because cracking was found at SPS, the potential for chloride contamination could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for cracking of stainless steel in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.4.1-002] – Cracking of stainless steel components exposed to air and condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

[3.4.1-074] – SPS has no in-scope stainless steel underground piping, piping components or tanks in the Steam and Power Conversion System.

[3.4.1-100] – SPS has 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 System.

[3.4.1-104] - SPS has no in-scope insulated stainless steel or nickel alloy piping, piping components, or tanks exposed to an external environment of air-outdoor or condensation n the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

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.

Loss of material due to pitting and crevice corrosion is an aging effect requiring management for stainless steel and nickel alloy components exposed to air or condensation in the Steam and Power Conversion Systems for SPS.

A review of SPS operating experience confirmed that loss of material of the external surfaces of stainless steel components in indoor air has occurred. Examples of externally initiated stress corrosion cracking are described in Section 3.4.2.2.2. Pitting was noted in some of the same general areas as cracking in the residual heat removal and safety injection systems.

Pitting and crevice corrosion of stainless steel and nickel alloy in air is supported by the presence of the same contaminants that support stress corrosion cracking. Since pitting was identified in some of the same general locations as cracking in the safety injection and residual heat removal systems, the potential for chloride contamination could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for loss of material due to pitting and crevice corrosion of stainless steel and nickel alloy in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.4.1-003] – Loss of material of stainless steel and nickel alloy components exposed to air and condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

[3.4.1-095] – SPS has no in-scope stainless steel or nickel alloy underground piping, piping components or tanks in the Steam and Power Conversion System.

[3.4.1-098] – SPS has 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 System.

[3.4.1-103] - SPS has no in-scope insulated stainless steel or nickel alloy piping, piping components, or tanks exposed to an external environment of air-outdoor or condensation n the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

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 B1.4, Operating Experience.

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.

[3.4.1-061] – A review of SPS operating experience confirms that loss of material due to recurring internal corrosion is not an aging effect that requires management for 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 in the Steam and Power Conversion Systems for SPS.

A review of SPS operating experience did not identify a history of cracking of in-scope aluminum alloy components. However, operating experience as discussed in Sections 3.4.2.2.2 and 3.4.2.2.3 confirmed that the external surfaces of some stainless steel components have experienced aging that was supported by the presence of halides.

Stress corrosion cracking of aluminum alloys in air is supported by the presence of the same contaminants that support loss of material and cracking in stainless steel. Since these aging effects have been identified in some stainless steel components, the potential for chloride contamination of aluminum alloy surfaces could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for cracking due to stress corrosion cracking of aluminum alloys in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.4.1-102] – SPS has 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 System.

[3.4.1-105] - SPS has no in-scope insulated aluminum piping, piping components, or tanks exposed to air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.4.1-109] – Cracking of aluminum alloy components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.

[3.4.1-112] – SPS has no in-scope aluminum underground piping, piping components or tanks in the Steam and Power Conversion System.

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.

[3.4.1-051] – Loss of material for steel piping components with an external environment of concrete can occur for components in the Steam and Power Conversion Systems that are potentially exposed to groundwater at the soil-concrete interface. SPS manages loss of material for steel piping, piping components exposed to concrete (and potentially exposed to groundwater) in the Steam and Power Conversion Systems with the Buried and Underground Piping and Tanks (B2.1.27) program.

[3.4.1-082] – SPS has no in-scope stainless steel 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.

Loss of material due to pitting and crevice corrosion is an aging effect requiring management for aluminum alloy components exposed to air in the Steam and Power Conversion Systems for SPS.

A review of SPS operating experience did not identify a history of loss of material of in-scope aluminum alloy components. However, operating experience as discussed in Sections 3.4.2.2.2 and 3.4.2.2.3 confirmed that the external surfaces of some stainless steel components have experienced aging that was supported by the presence of halides.

Pitting and crevice corrosion of aluminum alloys in air is supported by the presence of the same contaminants that support loss of material and cracking in stainless steel. Since these aging effects have been identified in some stainless steel components, the potential for chloride contamination of aluminum alloy surfaces could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for loss of material due to pitting and crevice corrosion of aluminum alloys in air environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.4.1-035] – Loss of material of aluminum alloy components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.

[3.4.1-094] – SPS has no in-scope aluminum underground piping, piping components or tanks in the Steam and Power Conversion System.

[3.4.1-097] – SPS has 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 System.

[3.4.1-119] - SPS has no in-scope insulated aluminum piping, piping components, or tanks exposed to air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.4.1-120] – SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion System.

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 piping, piping components exposed to any environment 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 or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) 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 and nickel alloy components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) 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.
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. SPS has no in-scope high-strength steel closure bolting exposed to air, soil, underground in the Steam and Power Conversion System. 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. with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Steam and Power Conversion System, components in Auxiliary Systems (boron recovery and sampling system) are aligned to this item.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.

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
3.4.1-014	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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Steam and Power Conversion System, components in Auxiliary Systems (primary and secondary plant gas supply, bearing cooling, component cooling, chilled water, boron recovery, water treatment, and sampling system) are aligned to this item.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Steam and Power Conversion System, components in Auxiliary Systems (primary and secondary plant gas supply, instrument air, bearing cooling, water treatment and circulating water) and Engineered Safety Features (recirculation spray and safety injection) 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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. No Steam and Power Conversion System components are aligned to this item. Only components in Engineered Safety Features (recirculation spray and safety injection) 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. SPS has no in-scope stainless steel or steel heat exchanger components exposed to raw water in the Steam and Power Conversion System. 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
3.4.1-020	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. SPS has no in-scope copper alloy or stainless steel piping, piping components exposed to raw water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-022	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. SPS has no in-scope stainless steel, copper alloy or steel heat exchanger tubes exposed to raw water in the Steam and Power Conversion System. 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. SPS has no in-scope stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.
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. SPS has no in-scope stainless steel heat exchanger components or piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-027	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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation.

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
3.4.1-028	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. SPS has no in-scope steel, stainless steel or copper alloy 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.
3.4.1-030	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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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. SPS has no in-scope gray cast iron or ductile iron piping, piping components exposed to soil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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.
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.

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
3.4.1-035	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 components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) 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 item 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	Consistent with NUREG-2191.
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. Loss of material and flow blockage of steel piping, piping components exposed to raw water is addressed in items 3.4.1-089 and 3.4.1-091 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	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
3.4.1-042	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	Not applicable. SPS has no in-scope aluminum piping, piping components exposed to lubricating oil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope aluminum heat exchanger tubes exposed to lubricating oil in the Steam and Power Conversion System. 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	Not applicable. SPS has no in-scope stainless steel, steel or copper alloy heat exchanger tubes exposed to lubricating oil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope stainless steel piping, piping components, tanks or closure bolting exposed to soil or concrete in the Steam and Power Conversion System. 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. SPS has no in-scope nickel alloy piping, piping components, tanks or closure bolting exposed to soil or concrete in the Steam and Power Conversion System. 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
3.4.1-050	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. Loss of material for steel piping, piping components exposed to concrete is addressed in item 3.4.1-050. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.8.
3.4.1-052	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. SPS has no in-scope aluminum piping, piping components exposed to gas in the Steam and Power Conversion System. 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. SPS has no in-scope copper alloy or copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System. 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.
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. SPS has no in-scope nickel alloy piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System. 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
3.4.1-057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not applicable. SPS has no in-scope PVC piping components exposed to air - indoor uncontrolled or condensation in the Steam and Power Conversion System. 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. SPS has no in-scope stainless steel piping, piping components exposed to gas in the Steam and Power Conversion System. 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	Consistent with NUREG-2191.
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.
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. Recurring internal corrosion has not been identified by a search of SPS operating experience for piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.6.
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. SPS has no in-scope steel (without an internal coating), stainless steel or aluminum tanks (within the scope of AMP XI.M29) exposed to treated water. Loss of material of steel with internal coating tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water is addressed in item 3.4.1-066 and 3.4.1-067. 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
3.4.1-063	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 insulated steel components exposed to air-outdoor is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. SPS has no in-scope insulated copper alloy (>15% Zn or >8% Al), piping, piping components, or tanks exposed to air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used.
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	Not applicable. SPS has no in-scope non-metallic thermal insulation exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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.

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
3.4.1-068	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. SPS has 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 or waste water in the Steam and Power Conversion System. 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. SPS has 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 System. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope stainless steel or aluminum piping components or tanks exposed to soil or concrete, and has no steel components exposed to soil or concrete in a carbonate/ bicarbonate environment in the Steam and Power Conversion systems. 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. SPS has no in-scope stainless steel underground piping, piping components or tanks in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.2.

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
3.4.1-075	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. SPS has 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 System. 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.
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. Hardening or loss of strength of elastomer components exposed to air is addressed in item 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. SPS has no in-scope stainless steel piping, piping components exposed to concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.8.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. No Steam and Power Conversion System components are aligned to this item. Only components in Auxiliary Systems (chemical and volume control) are aligned to this item.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation.

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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. In addition to Steam and Power Conversion System, components in Auxiliary Systems (instrument air, primary grade water, chemical and volume control and sampling system) are aligned to this item.
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. SPS has 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 System. 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	Consistent with NUREG-2191 for loss of material. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
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. SPS has 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 System. 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	Consistent with NUREG-2191 for loss of material. Flow blockage is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow. No Steam and Power Conversion System components are aligned to this item. Only components in Auxiliary Systems (service water) 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
3.4.1-092	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. SPS has no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Steam and Power Conversion System. 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. SPS has no in-scope aluminum underground piping, piping components or tanks in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.9.
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. SPS has no in-scope stainless steel or nickel alloy underground piping, piping components or tanks in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.3.
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. SPS has 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 System. 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
3.4.1-097	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. SPS has 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 System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.9.
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. SPS has 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 System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.3.
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. SPS has 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 System. 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. SPS has 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 System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.2.

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
3.4.1-101	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. SPS has 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 System. 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. SPS has 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 System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.7.
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. SPS has no in-scope insulated stainless steel or nickel alloy piping, piping components, or tanks exposed to an external environment of air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.3.

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
3.4.1-104	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. SPS has no in-scope insulated stainless steel or nickel alloy piping, piping components or tanks exposed to an external environment of air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.2.
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. SPS has no in-scope insulated aluminum piping, piping components or tanks exposed to air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.7.

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
3.4.1-106	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	Not applicable. SPS has no in-scope copper alloy (>15% Zn or >8% Al) components exposed to outdoor air or external condensation in the Steam and Power Conversion systems. The contaminants necessary to promote cracking of copper alloy (>15% Zn) components are not expected in an indoor air or internal condensation environment. Aging of copper alloy (>15% Zn) components in indoor air or internal condensation environments in the Steam and Power Conversion systems are aligned to item 3.4.1-054. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope copper alloy (>15% Zn or >8% Al) tanks exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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 is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. See further evaluation in Section 3.4.2.2.7.

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
3.4.1-112	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. SPS has no in-scope aluminum underground piping, piping components or tanks in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.7.
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. SPS has 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. SPS has 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 System. The associated NUREG-2191 aging items are not used.
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. SPS has 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. SPS has no in-scope aluminum piping, piping components or tanks exposed to soil or concrete in the Steam and Power Conversion System. 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
3.4.1-119	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. SPS has no in-scope insulated aluminum piping, piping components, or tanks exposed to air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.9.
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. SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.4.2.2.9.
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.

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
3.4.1-123	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. Loss of material of elastomer components exposed to air is addressed in item 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. SPS has no in-scope PVC piping, piping components or tanks exposed to concrete in the Steam and Power Conversion System. 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. SPS has no in-scope PVC piping, piping components or tanks exposed to soil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. SPS has 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 System. 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. SPS has no in-scope aluminum piping, piping components or tanks exposed to air with borated water leakage in the Steam and Power Conversion System. 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. SPS has no in-scope copper alloy piping, piping components exposed to concrete in the Steam and Power Conversion System. 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
3.4.1-129	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. SPS has no in-scope copper alloy piping, piping components exposed to soil or an underground environment in the Steam and Power Conversion System. 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. SPS has 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	Not applicable. SPS has no in-scope copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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; 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. SPS has 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. SPS has no in-scope titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in the Steam and Power Conversion System. 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
3.4.1-135	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	Consistent with NUREG-2191 for hardening or loss of strength, loss of material and cracking or blistering. Hardening or loss of strength, loss of material, and cracking or blistering of polymeric components exposed to air are managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Flow blockage is not an applicable aging effect requiring management for external surfaces, or for nonsafety-related components that do not support a function of delivering downstream flow.

Results Tables: Steam and Power Conversion Systems AMR Results

Table 3.4.2-1 Steam and Power Conversion System - Main Turbine - 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
Turbine casing	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
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.A.SP-71	3.4.1-014	B
Turbine casing (rupture disc)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B

Table 3.4.2-1 Plant-Specific Notes: None

Table 3.4.2-2 Steam and Power Conversion System - Electro-Hydraulic 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
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
Filter housing	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	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) 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
Flow indicator	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
Heat exchanger (electro-hydraulic oil - channel)	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.A.S-23	3.4.1-025	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	C

Table 3.4.2-2 Steam and Power Conversion System - Electro-Hydraulic 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 (electro-hydraulic oil - shell)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	C
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	C
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
Piping	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (electro-hydraulic control oil)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (transfer pump)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-2 Steam and Power Conversion System - Electro-Hydraulic 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 (electro-hydraulic oil reservoir)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
Tank (high pressure accumulator)	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
			(I) Gas	None	None	VIII.I.SP-4	3.4.1-059	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (low pressure accumulator)	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
			(I) Gas	None	None	VIII.I.SP-4	3.4.1-059	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Valve body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	A
		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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-2 Steam and Power Conversion System - Electro-Hydraulic 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-2 Plant-Specific Notes: None

Table 3.4.2-3 Steam and Power Conversion System - Lubricating Oil - 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
Filter housing	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Flow indicator	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	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
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1
Heat exchanger (generator seal oil - channel)	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.A.S-23	3.4.1-025	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	C
Heat exchanger (generator seal oil - 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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A
Heat exchanger (lubricating oil - channel)	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.A.S-23	3.4.1-025	B
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	C
Heat exchanger (lubricating oil - 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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A

Table 3.4.2-3 Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heater housing (lubricating oil conditioner)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
Piping, piping components	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	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
Pump casing (bearing lift)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (fill)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (oil conditioner)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-3 Steam and Power Conversion System - Lubricating Oil - 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 (turbine lubricating oil)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Sight glass	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) 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
		Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Lubricating oil	None	None	VIII.I.SP-10	3.4.1-055	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Sight glass (body)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	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
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1
		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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-3 Steam and Power Conversion System - Lubricating Oil - 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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (generator seal oil)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (lubricating oil)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (oil conditioner drain and collection)	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
			(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 3.4.2-3 Steam and Power Conversion System - Lubricating Oil - 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	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	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)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	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 3.4.2-3 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.4.2-4 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
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 restrictor (venturi)	RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	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	B
				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	B
Heat exchanger (moisture separator reheater - shell/channel)	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
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	C
				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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	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	B
				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	B

Table 3.4.2-4 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	3.4.1-003	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.B1.SP-118c	3.4.1-002	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.B1.SP-127c	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	B
				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	B
		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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-60	3.4.1-037	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	B
				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.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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A

Table 3.4.2-4 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
Steam trap	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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
Strainer 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
			(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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Condensation	None	None	VIII.I.SP-6	3.4.1-054	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	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	B
				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	B

Table 3.4.2-4 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	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-60	3.4.1-037	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	B
				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.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	B

Table 3.4.2-4 Plant-Specific Notes: None

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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
Filter housing	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
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
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) Fuel oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H1.A-660	3.3.1-085	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-136	3.3.1-071	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	B
				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	B
Heat exchanger (auxiliary boiler drum)	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.E.S-23	3.4.1-025	B

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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 (converter 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
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	C
				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	B
Heating coil (ventilation unit heater)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	C
			(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	B
Humidifier	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
			(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	B
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-136	3.3.1-071	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	B
				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	B
			(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	B
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-136	3.3.1-071	A

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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	(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	B
		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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-105	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-105	3.3.1-070	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-436	3.4.1-089	A, 1, 2
			(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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	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, 2

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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 (auxiliary boiler feed)	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
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
Pump casing (auxiliary boiler fuel oil)	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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-105	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-105	3.3.1-070	A
Pump casing (chemical injection)	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
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
Pump casing (condensate)	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.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
Pump casing (fuel oil transfer)	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
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-105	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-105	3.3.1-070	A

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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)	VIII.H.S-29	3.4.1-034	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
				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, 2
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	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-457c	3.4.1-109	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-147b	3.4.1-035	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-254	3.3.1-048	B
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	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	B
					Selective Leaching (B2.1.21)	VIII.E.SP-55	3.4.1-033	A

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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) 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	B
		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) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-105	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-105	3.3.1-070	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	B
			(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, 2
Tank (blowdown)	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
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
Tank (chemical mixing)	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
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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 receiver)	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.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
Tank (deaerator)	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
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
Tank (drain)	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
			(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, 2
Trap 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) 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	B
		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.C.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-71	3.4.1-014	B

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.E.SP-8	3.4.1-027	B
			(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	B
			(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	B
		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) 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	B
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B

Table 3.4.2-5 Steam and Power Conversion System - Heating - 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	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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	B
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-105	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.H1.AP-105	3.3.1-070	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-436	3.4.1-089	A, 1, 2
			(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	B
			(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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
			(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, 2

Table 3.4.2-5 Plant-Specific Notes:

1. Raw water environment is present in the domestic water supply to chemical mixing tanks.
2. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.4.2-6 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	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
Expansion joint	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-127b	3.4.1-003	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-157	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-157	3.4.1-084	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-408	3.4.1-060	A

Table 3.4.2-6 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
Piping, piping components	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
			(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
			(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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	A
						VIII.C.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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
Steam trap	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
		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	B

Table 3.4.2-6 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
Strainer body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.C.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
		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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A

Table 3.4.2-6 Plant-Specific Notes: None

Table 3.4.2-7 Steam and Power Conversion System - Auxiliary 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
Air ejector	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
			(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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	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
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	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	B
				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	B
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	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	B
				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	B
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.C.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.C.SP-88	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.C.SP-87	3.4.1-085	B

Table 3.4.2-7 Steam and Power Conversion System - Auxiliary 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	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)	VII.C1.A-778	3.3.1-249	C
			(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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A
Pump casing (drain receiver)	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.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B
					Selective Leaching (B2.1.21)	VIII.A.SP-27	3.4.1-033	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
Steam trap	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) 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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	A

Table 3.4.2-7 Steam and Power Conversion System - Auxiliary 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
Steam trap	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	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	B
				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	B
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.C.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.C.SP-88	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.C.SP-87	3.4.1-085	B
		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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	A

Table 3.4.2-7 Steam and Power Conversion System - Auxiliary 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	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) 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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	A
Tank (drain receiver)	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 (B2.1.28)	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 (B2.1.28)	VIII.E.S-414	3.4.1-067	A

Table 3.4.2-7 Steam and Power Conversion System - Auxiliary 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	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.B1.SP-127b	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	B
				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	B
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.C.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.C.SP-88	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.C.SP-87	3.4.1-085	B
		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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	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.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	B

Table 3.4.2-7 Plant-Specific Notes: None

Table 3.4.2-8 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
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
		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
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-141	3.4.1-050	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Filter housing	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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	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) 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
Flow element	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-127b	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	B

Table 3.4.2-8 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
Flow restrictor (venturi)	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-127b	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	B
				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	B
Heat exchanger (first point feedwater heater - channel)	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
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	C
				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.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B
Heat exchanger (first point feedwater heater - 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
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	C
				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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	A
Heat exchanger (main feedwater pump stuffing box jacket)	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.G.S-23	3.4.1-025	B
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-127b	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	B

Table 3.4.2-8 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;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
			(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	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-127b	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	B
		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
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	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	B
				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 3.4.2-8 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
Pump casing (auxiliary feedwater booster)	PB	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.A.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	B
					Selective Leaching (B2.1.21)	VIII.G.SP-27	3.4.1-033	A
Pump casing (auxiliary feedwater lubricating 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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
Pump casing (auxiliary feedwater)	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) 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.G.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.G.SP-74	3.4.1-014	B
Pump casing (main feedwater lubricating oil)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
Pump casing (main feedwater)	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
			(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	B
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Lubricating oil	None	None	VIII.I.SP-10	3.4.1-055	A

Table 3.4.2-8 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
Sight glass (body)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-92	3.4.1-043	A
Strainer body	LB;PB	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
			(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.G.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.G.SP-74	3.4.1-014	B
					Selective Leaching (B2.1.21)	VIII.G.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) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	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	B
Strainer element	FLT	Stainless steel	(E) 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	B
		Steel	(E) 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	B
Tank (auxiliary feedwater pump lubricating 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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A

Table 3.4.2-8 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
Tank (main feedwater pump lubricating oil)	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
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
Turbine casing	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) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.G.SP-60	3.4.1-037	A
Valve body	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	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	B
		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	None	None	VIII.I.SP-6	3.4.1-054	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
		Polymer	(I) Air – dry	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.D1.S-483b	3.4.1-135	A, 1
			(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-483a	3.4.1-135	A

Table 3.4.2-8 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;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.D1.SP-127b	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-95	3.4.1-044	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	B
			(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	B
				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	B
		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.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	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	B

Table 3.4.2-8 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for external surfaces or for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.4.2-9 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
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 – 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) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-141	3.4.1-050	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Condenser (hotwell)	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
			(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-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B
			(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	B
				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	B
Heat exchanger (drain cooler - channel)	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
			(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-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B

Table 3.4.2-9 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
Heat exchanger (drain 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
			(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-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B
Heat exchanger (feedwater heater - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	B
		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) Treated water	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	C
				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-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B

Table 3.4.2-9 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
Heat exchanger (feedwater heater - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	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	B
		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) Treated water	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	C
				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-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B
Heat exchanger (gland steam condenser - channel)	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
			(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-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B
Heat exchanger (gland steam condenser - 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
			(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-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	B
Heat exchanger (pump motor oil - cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.E.SP-8	3.4.1-027	D
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-92	3.4.1-043	C
					One-Time Inspection (B2.1.20)	VIII.E.SP-92	3.4.1-043	C

Table 3.4.2-9 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
Heat exchanger (pump stuffing box - jacket)	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.E.S-23	3.4.1-025	B
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B
			(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	B
				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	B
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A

Table 3.4.2-9 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
Piping, piping components	LB;PB;SI	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 – outdoor	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-402a	3.4.1-063	A, 1
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	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.E.S-432	3.4.1-081	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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
Pump casing (condensate)	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
			(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-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
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
			(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-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B

Table 3.4.2-9 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
Strainer 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
			(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-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
Tank (emergency condensate makeup)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VIII.E.SP-115	3.4.1-030	B
			(E) Soil	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VIII.E.SP-115	3.4.1-030	B
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VIII.E.S-414	3.4.1-067	A
Tank (emergency condensate storage)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VIII.E.SP-115	3.4.1-030	B
			(E) Soil	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VIII.E.SP-115	3.4.1-030	B
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	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 (B2.1.28)	VIII.E.S-414	3.4.1-067	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)	VIII.H.S-29	3.4.1-034	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-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A

Table 3.4.2-9 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
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B
		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 – outdoor	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-402a	3.4.1-063	A, 1
			(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-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A

Table 3.4.2-9 Plant-Specific Note:

1. Cited GALL item VIII.H.S-402a includes “cracking” aging effect that is only applicable for copper alloy (>15% Zn or >8% Al). Cracking is not an applicable aging effect for steel components.

Table 3.4.2-10 Steam and Power Conversion System - Condensate Polishing - 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
Piping, piping components	LB	Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
			(I) Waste water	Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-551	3.3.1-175	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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	B
		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) 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-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A
		Steel with internal lining	(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) Waste water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.E5.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.E5.A-414	3.3.1-139	A

Table 3.4.2-10 Steam and Power Conversion System - Condensate Polishing - 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	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	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-272	3.3.1-095	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-127b	3.4.1-003	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)	VIII.H.S-29	3.4.1-034	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-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
			(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 3.4.2-10 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.4.2-11 Steam and Power Conversion System - Steam 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	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
Expansion joint	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	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	B
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	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	B
				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	B
		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) 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.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
Heat exchanger (heater drain pump motor oil cooling coil)	LB	Copper alloy	(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.E.SP-8	3.4.1-027	D
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	C
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	C
Heat exchanger (heater drain pump stuffing box jacket)	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
			(I) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.A.S-23	3.4.1-025	B

Table 3.4.2-11 Steam and Power Conversion System - Steam 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
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
			(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	B
				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	B
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-408	3.4.1-060	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	B
				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	B
				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)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-11 Steam and Power Conversion System - Steam 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	Steel	(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-60	3.4.1-037	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.A.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.A.SP-71	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.A.S-15	3.4.1-005	A
						VIII.C.S-408	3.4.1-060	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.A.S-432	3.4.1-081	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	B
				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
			(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
Pump casing (gland steam condensate)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	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-272	3.3.1-095	A, 1
Pump casing (heater drains)	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
			(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.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-16	3.4.1-005	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

Table 3.4.2-11 Steam and Power Conversion System - Steam 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
Sight glass (body)	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-457c	3.4.1-109	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.E.SP-147b	3.4.1-035	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-90	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.E.SP-90	3.4.1-016	B
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	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
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	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	B
				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	B
		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) 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.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
Steam trap	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
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.A.SP-71	3.4.1-014	B

Table 3.4.2-11 Steam and Power Conversion System - Steam 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
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
			(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
				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
Tank (gland steam condenser receiver)	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
			(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
Tank (heater drain receiver, moisture separator drain pot)	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
			(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.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	B
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Condensation	None	None	VIII.I.SP-6	3.4.1-054	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-272	3.3.1-095	A, 1
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Condensation	None	None	VIII.I.SP-6	3.4.1-054	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
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1

Table 3.4.2-11 Steam and Power Conversion System - Steam 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
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.A.SP-127b	3.4.1-003	A
			(I) Condensation	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.A.SP-118c	3.4.1-002	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.A.SP-127c	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	B
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	B
			(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	B
				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	B
			(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)	VIII.H.S-29	3.4.1-034	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-60	3.4.1-037	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.A.SP-71	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.A.S-15	3.4.1-005	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.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	B
			(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 3.4.2-11 Plant-Specific Note:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.4.2-12 Steam and Power Conversion System - 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
Heat exchanger (blowdown - channel)	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
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	C
				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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.F.S-16	3.4.1-005	C
Heat exchanger (blowdown - 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
			(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	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.F.S-16	3.4.1-005	C
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B
			(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	B
				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	B

Table 3.4.2-12 Steam and Power Conversion System - 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
Piping, piping components	LB;PB	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.R-47	3.1.1-069	C, 1
					Water Chemistry (B2.1.2)	IV.D1.R-47	3.1.1-069	D, 1
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-233	3.1.1-077	C, 1
			(I) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.R-47	3.1.1-069	C, 1
					Water Chemistry (B2.1.2)	IV.D1.R-47	3.1.1-069	D, 1
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-233	3.1.1-077	C, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B
			(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	B
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	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	B
		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)	VII.F2.A-778	3.3.1-249	C
			(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.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	C
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.F.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A

Table 3.4.2-12 Steam and Power Conversion System - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B
			(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	B
				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	B
		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	C
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.F.S-16	3.4.1-005	A

Table 3.4.2-12 Plant-Specific Note:

1. This component represents the blowdown piping within the steam generator. The treated water >60°C (>140°F) environment present in the secondary side of the steam generator is equivalent to the NUREG-2191 environment of secondary feedwater or steam.

Table 3.4.2-13 Steam and Power Conversion System - Steam Generator Recirculation and Transfer - 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
Heat exchanger (steam generator recirculation channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	3.4.1-003	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-80	3.4.1-085	B
Heat exchanger (steam generator recirculation 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) Closed-cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.F.S-23	3.4.1-025	B
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B

Table 3.4.2-13 Steam and Power Conversion System - Steam Generator Recirculation and Transfer - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B
		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	B
Pump casing (steam generator recirculation and transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B

Table 3.4.2-13 Steam and Power Conversion System - Steam Generator Recirculation and Transfer - 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	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-118b	3.4.1-002	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.F.SP-127b	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	B
		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	B

Table 3.4.2-13 Plant-Specific Notes: None

Tables 3.4.2-1 through 3.4.2-13 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.

Intentionally Blank

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 2.4.1, Containments, Structures, and Component Supports, 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.

- Containment (Section 2.4.1.1)
- Auxiliary Building Structure (Section 2.4.1.2)
- Discharge Canal (Section 2.4.1.3)
- Intake Canal (Section 2.4.1.4)
- Fuel Building (Section 2.4.1.5)
- Discharge Tunnel and Seal Pit (Section 2.4.1.6)
- High Level Intake Structure (Section 2.4.1.7)
- Low Level Intake Structure (Section 2.4.1.8)
- Black Battery Building (Section 2.4.1.9)
- Central Alarm Station (Section 2.4.1.10)
- Condensate Polishing Building (Section 2.4.1.11)
- Laundry Facility (Section 2.4.1.12)
- Machine Shop (Section 2.4.1.13)
- Radwaste Facility (Section 2.4.1.14)
- SBO Building (Section 2.4.1.15)
- Service Building (Section 2.4.1.16)
- Turbine Building (Section 2.4.1.17)
- Containment Spray Pump Building (Section 2.4.1.18)
- Fire Pump House (Section 2.4.1.19)
- Fuel Oil Pump House (Section 2.4.1.20)
- Main Steam Valve House (Section 2.4.1.21)
- Safeguards Building (Section 2.4.1.22)
- Buried Fuel Oil Tank Missile Barrier (Section 2.4.1.23)
- Chemical Addition Tank Foundation (Section 2.4.1.24)

- Duct Banks (Section 2.4.1.25)
- Emergency Condensate Tank Foundations and Missile Barriers (Section 2.4.1.26)
- Fire Protection and Domestic Water Tank Foundation (Section 2.4.1.27)
- Fuel Oil Line Missile Barrier (Section 2.4.1.28)
- Fuel Oil Storage Tank Dike (Section 2.4.1.29)
- Manholes (Section 2.4.1.30)
- Reactor Containment Subsurface Drainage System Access Shaft (Section 2.4.1.31)
- Refueling Water Storage Tank Foundation (Section 2.4.1.32)
- SBO Structures for Offsite Power (Section 2.4.1.33)
- Security Lighting Poles (Section 2.4.1.34)
- Transformer Firewalls and Dikes (Section 2.4.1.35)
- Component Supports (Section 2.4.1.36)
- Miscellaneous Structural Commodities (Section 2.4.1.37)
- NSSS Supports (Section 2.4.1.38)

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, Containments, Structures and Component Supports - Containment - Aging Management Evaluation
- Table 3.5.2-2, Containments, Structures and Component Supports - Auxiliary Building Structure - Aging Management Evaluation
- Table 3.5.2-3, Containments, Structures and Component Supports - Discharge Canal - Aging Management Evaluation
- Table 3.5.2-4, Containments, Structures and Component Supports - Intake Canal - Aging Management Evaluation
- Table 3.5.2-5, Containments, Structures and Component Supports - Fuel Building Structure - Aging Management Evaluation
- Table 3.5.2-6, Containments, Structures and Component Supports - Discharge Tunnel and Seal Pit - Aging Management Evaluation
- Table 3.5.2-7, Containments, Structures and Component Supports - High Level Intake Structure - Aging Management Evaluation
- Table 3.5.2-8, Containments, Structures and Component Supports - Low Level Intake Structure - Aging Management Evaluation
- Table 3.5.2-9, Containments, Structures and Component Supports - Black Battery Building - Aging Management Evaluation
- Table 3.5.2-10, Containments, Structures and Component Supports - Central Alarm Station - Aging Management Evaluation
- Table 3.5.2-11, Containments, Structures and Component Supports - Condensate Polishing Building - Aging Management Evaluation
- Table 3.5.2-12, Containments, Structures and Component Supports - Laundry Facility - Aging Management Evaluation
- Table 3.5.2-13, Containments, Structures and Component Supports - Machine Shop - Aging Management Evaluation
- Table 3.5.2-14, Containments, Structures and Component Supports - Radwaste Facility - Aging Management Evaluation
- Table 3.5.2-15, Containments, Structures and Component Supports - SBO Building - Aging Management Evaluation
- Table 3.5.2-16, Containments, Structures and Component Supports - Service Building - Aging

3.5.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.5.2.1.1 Containment

Materials

The materials of construction for the containment structural members are:

- Coatings
- Concrete
- Concrete block
- Dissimilar metal welds
- Elastomer, rubber and other similar materials
- Grout
- Porous concrete
- Reinforced concrete
- Stainless steel
- Steel

Environment

The containment structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Groundwater
- Soil
- Treated borated water
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the containment structural members, require management:

- Cracking
- Cracking and distortion
- 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 sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the containment structural members:

- 10 CFR Part 50, Appendix J (B2.1.32)
- ASME Section XI, Subsection IWE (B2.1.29)
- ASME Section XI, Subsection IWL (B2.1.30)
- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- One-Time Inspection (B2.1.20)
- Protective Coating Monitoring and Maintenance (B2.1.36)
- Structures Monitoring (B2.1.34)
- Water Chemistry (B2.1.2)

3.5.2.1.2 Auxiliary Building Structure

Materials

The materials of construction for the auxiliary building structure structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Reinforced concrete
- Steel

Environment

The auxiliary building structure structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary building 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
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary building structure structural members:

- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.3 Discharge Canal

Materials

The materials of construction for the discharge canal structural members are:

- Concrete
- Earthfill (rip-rap, stone, soil)

Environment

The discharge canal structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the discharge canal structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of form
- Loss of material
- 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 discharge canal structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.4 Intake Canal

Materials

The materials of construction for the intake canal structural members are:

- Concrete
- Earthfill (rip-rap, stone, soil)

Environment

The intake canal structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the intake canal structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of form
- Loss of material
- 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 intake canal structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.5 Fuel Building Structure

Materials

The materials of construction for the fuel building structure structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Stainless steel
- Steel

Environment

The fuel building structure structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Groundwater
- Soil
- Treated borated water
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the fuel building 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
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the fuel building structure structural members:

- Boric Acid Corrosion (B2.1.4)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)
- Water Chemistry (B2.1.2)

3.5.2.1.6 Discharge Tunnel and Seal Pit

Materials

The materials of construction for the discharge tunnel and seal pit structural members are:

- Concrete

Environment

The discharge tunnel and seal pit 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 discharge tunnel and seal pit 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 discharge tunnel and seal pit structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.7 High Level Intake Structure

Materials

The materials of construction for the high level intake structure structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Steel

Environment

The high level intake structure structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the high level 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 high level intake structure structural members:

- Fire Protection (B2.1.15)
- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.8 Low Level Intake Structure

Materials

The materials of construction for the low level intake structure structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Fiberglass
- HDPE
- Masonry walls
- Reinforced concrete
- Steel

Environment

The low level intake structure structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Groundwater
- Raw water
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the low level intake structure structural members, require management:

- Cracking
- Cracking, blistering, loss of material
- 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 low level intake structure structural members:

- Fire Protection (B2.1.15)
- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.9 Black Battery Building

Materials

The materials of construction for the black battery building structural members are:

- Concrete
- Steel

Environment

The black battery building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the black battery 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the black battery building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.10 Central Alarm Station

Materials

The materials of construction for the central alarm station structural members are:

- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The central alarm station structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the central alarm station 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 preload
- Loss of sealing

Aging Management Programs

The following aging management programs manage the aging effects for the central alarm station structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.11 Condensate Polishing Building

Materials

The materials of construction for the condensate polishing building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The condensate polishing building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the condensate polishing 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 preload
- Loss of sealing

Aging Management Programs

The following aging management programs manage the aging effects for the condensate polishing building structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.12 Laundry Facility

Materials

The materials of construction for the laundry facility structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The laundry facility structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the laundry facility 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 sealing

Aging Management Programs

The following aging management programs manage the aging effects for the laundry facility structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.13 Machine Shop

Materials

The materials of construction for the machine shop structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The machine shop structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the machine shop 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 preload
- Loss of sealing

Aging Management Programs

The following aging management programs manage the aging effects for the machine shop structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.14 Radwaste Facility

Materials

The materials of construction for the radwaste facility structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The radwaste facility structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the radwaste facility 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

Aging Management Programs

The following aging management programs manage the aging effects for the radwaste facility structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.15 SBO Building

Materials

The materials of construction for the SBO building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The SBO building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the SBO 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

Aging Management Programs

The following aging management programs manage the aging effects for the SBO building structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.16 Service Building

Materials

The materials of construction for the service building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Reinforced concrete
- Steel

Environment

The service building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the 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

Aging Management Programs

The following aging management programs manage the aging effects for the service building structural members:

- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.17 Turbine Building

Materials

The materials of construction for the turbine building structural members are:

- 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

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

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 (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.18 Containment Spray Pump Building

Materials

The materials of construction for the containment spray pump building structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The containment spray pump 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 containment spray pump 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

Aging Management Programs

The following aging management programs manage the aging effects for the containment spray pump building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.19 Fire Pump House

Materials

The materials of construction for the fire pump house structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The fire pump house 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 fire pump house 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

Aging Management Programs

The following aging management programs manage the aging effects for the fire pump house structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.20 Fuel Oil Pump House

Materials

The materials of construction for the fuel oil pump house structural members are:

- Concrete
- Concrete block
- Steel

Environment

The fuel oil pump house 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 fuel oil pump house 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

Aging Management Programs

The following aging management programs manage the aging effects for the fuel oil pump house structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.21 Main Steam Valve House

Materials

The materials of construction for the main steam valve house structural members are:

- Concrete
- Steel

Environment

The main steam valve house 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 main steam valve house 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

Aging Management Programs

The following aging management programs manage the aging effects for the main steam valve house structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.22 Safeguards Building

Materials

The materials of construction for the safeguards building structural members are:

- Concrete
- Steel

Environment

The safeguards 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 safeguards 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

Aging Management Programs

The following aging management programs manage the aging effects for the safeguards building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.23 Buried Fuel Oil Tank Missile Barrier

Materials

The materials of construction for the buried fuel oil tank missile barrier structural members are:

- Concrete

Environment

The buried fuel oil tank missile barrier structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the buried fuel oil tank missile barrier 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

Aging Management Programs

The following aging management programs manage the aging effects for the buried fuel oil tank missile barrier structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.24 Chemical Addition Tank Foundation

Materials

The materials of construction for the chemical addition tank foundation structural members are:

- Concrete
- Grout
- Steel

Environment

The chemical addition tank foundation structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the chemical addition tank foundation 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
- Reduction in concrete anchor capacity

Aging Management Programs

The following aging management programs manage the aging effects for the chemical addition tank foundation structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.25 Duct Banks

Materials

The materials of construction for the duct banks structural members are:

- Concrete
- Steel

Environment

The duct banks structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

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
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the duct banks structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.26 Emergency Condensate Tank Foundations and Missile Barriers

Materials

The materials of construction for the emergency condensate tank foundations and missile barriers structural members are:

- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The emergency condensate tank foundations and missile barriers structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the emergency condensate tank foundations and missile barriers 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

Aging Management Programs

The following aging management programs manage the aging effects for the emergency condensate tank foundations and missile barriers structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.27 Fire Protection and Domestic Water Tank Foundation

Materials

The materials of construction for the fire protection and domestic water tank foundation structural members are:

- Concrete

Environment

The fire protection and domestic water tank foundation structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the fire protection and domestic water tank foundation 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

Aging Management Programs

The following aging management programs manage the aging effects for the fire protection and domestic water tank foundation structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.28 Fuel Oil Line Missile Barrier

Materials

The materials of construction for the fuel oil line missile barrier structural members are:

- Concrete
- Steel

Environment

The fuel oil line missile barrier structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the fuel oil line missile barrier 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

Aging Management Programs

The following aging management programs manage the aging effects for the fuel oil line missile barrier structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.29 Fuel Oil Storage Tank Dike

Materials

The materials of construction for the fuel oil storage tank dike structural members are:

- Concrete

Environment

The fuel oil storage tank dike structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the fuel oil storage tank dike 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

Aging Management Programs

The following aging management programs manage the aging effects for the fuel oil storage tank dike structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.30 Manholes

Materials

The materials of construction for the manholes structural members are:

- Concrete
- Steel

Environment

The manholes structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the 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

Aging Management Programs

The following aging management programs manage the aging effects for the manholes structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.31 Reactor Containment Subsurface Drainage System Access Shaft

Materials

The materials of construction for the reactor containment subsurface drainage system access shaft structural members are:

- Concrete

Environment

The reactor containment subsurface drainage system access shaft structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the reactor containment subsurface drainage system access shaft structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)

Aging Management Programs

The following aging management programs manage the aging effects for the reactor containment subsurface drainage system access shaft structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.32 Refueling Water Storage Tank Foundation

Materials

The materials of construction for the refueling water storage tank foundation structural members are:

- Concrete
- Elastomer, rubber and other similar materials
- Grout
- Steel

Environment

The refueling water storage tank foundation structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the refueling water storage tank foundation 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
- Reduction in concrete anchor capacity

Aging Management Programs

The following aging management programs manage the aging effects for the refueling water storage tank foundation structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.33 SBO Structures for Offsite Power

Materials

The materials of construction for the SBO structures for offsite power structural members are:

- Concrete
- Concrete block
- Steel
- Wood

Environment

The SBO structures for offsite power structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the SBO structures for offsite power structural members, require management:

- Change in material properties
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the SBO structures for offsite power structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.34 Security Lighting Poles

Materials

The materials of construction for the security lighting poles structural members are:

- Concrete

Environment

The security lighting poles structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the security lighting poles 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

Aging Management Programs

The following aging management programs manage the aging effects for the security lighting poles structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.35 Transformer Firewalls and Dikes

Materials

The materials of construction for the transformer firewalls and dikes structural members are:

- Concrete

Environment

The transformer firewalls and dikes structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the transformer firewalls and dikes 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

Aging Management Programs

The following aging management programs manage the aging effects for the transformer firewalls and dikes structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.36 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 with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the component supports subcomponents, require management:

- Cracking
- Cumulative fatigue damage
- 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 (B2.1.31)
- Boric Acid Corrosion (B2.1.4)
- Structures Monitoring (B2.1.34)

3.5.2.1.37 Miscellaneous Structural Commodities

Materials

The materials of construction for the miscellaneous structural commodities subcomponents are:

- 3M Interam, Pyrocrete, Bio-fire (bio K-10 mortar)
- Aluminum
- Cera Fiber, Cera Blanket, Marinite board
- Cerafiber, Pyrocrete, Micarta, Dux Seal, KBS sealbags, mineral wool, gypsum
- Elastomer
- Elastomer, rubber and other similar materials
- Stainless steel
- Steel
- Thermo-lag, Marinite

Environment

The miscellaneous structural commodities subcomponents are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the miscellaneous structural commodities subcomponents, require management:

- Cracking
- Hardening, loss of strength, shrinkage
- Loss of material
- Loss of material, change in material properties, cracking/delamination
- Loss of material, change in material properties, cracking/delamination, separation
- Loss of sealing

Aging Management Programs

The following aging management programs manage the aging effects for the miscellaneous structural commodities subcomponents:

- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.34)

3.5.2.1.38 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
- Cumulative fatigue damage
- 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 (B2.1.31)
- Boric Acid Corrosion (B2.1.4)
- Structures Monitoring (B2.1.34)

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.

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] – UFSAR Section 2.4.3.5 discusses allowable and measured site settlements. A site survey conducted in May 1975 indicated that site settlement was not significant at the SPS. A follow-up survey program was continued over the next two years to further monitor site elevations. The follow-up survey program indicated that a small amount of heave had occurred in the vicinity of both containment structures; however, the differential movement between safety-related structures was below the allowable tolerance of 0.5 inches. The maximum differential movement had been about 0.2 inches. Inspection of structural interfaces showed no visible evidence of differential displacements. A settlement monitoring program technical report documents that vertical movement of the containment structures was measured from June 1975 through July 1989 at which time survey monitoring was no longer deemed necessary. Differential movements did not exceed 0.25 inches, which is below the allowable limit of 0.5 inch. Accessible concrete components are monitored by the Structures Monitoring program (B2.1.34) for components within the scope of the Structures Monitoring program (B2.1.34) or the ASME Section XI, Subsection IWL program (B2.1.30) for components within the scope of the ASME Section XI, Subsection IWL program (B2.1.30) to confirm the absence of any visible effects due to settlement.

[3.5.1-002] – UFSAR Section 2.4.7.1 and 15.5.1 discuss the containment foundation design. The containment structures are founded on preconsolidated clays, using reinforced-concrete mats. A drainage layer consisting of compacted granular fill was placed directly on the clays. A layer of porous concrete was placed immediately below the mat to serve as an internal drainage system. Drains under the Containment connect with and drain to this drainage layer. This layer in turn connects with and is drained by a system of permanent sumps to keep the water level below the top surface of the foundation mat. The dewatering system is within the scope of subsequent license renewal and is subject to aging management as part of the plumbing system to ensure the continued functionality of the system during the subsequent period of extended operation. Accessible concrete components are monitored by the Structures Monitoring program (B2.1.34) to confirm the absence of any visible effects 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 of a plant-specific AMP if any portion of the concrete containment components exceeds specified temperature limits [{i.e., general area temperature greater than 66°C (Celsius) [150°F (Fahrenheit)] and local area temperature greater than 93°C (200°F)}. 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-1 (Appendix A.1 of this SRP SLR).

[3.5.1-003] – UFSAR Section 15.5.1.8 discusses high temperature pipe penetrations. Containment structure piping penetrations for all thermally hot (over 150°F) piping systems are sleeved penetrations. The main steam and feedwater penetrations are provided with adequate space between the piping and the sleeve for the necessary pipe insulation, and for a pipe coil outside the insulation through which component cooling water is circulated. This cooling coil reduces the temperature of the sleeve and prevents any excessive heating (over 150°F) of the concrete in contact with the sleeve. UFSAR Section 15.6.2.2.1 discusses the reactor vessel support, which consists of six sliding foot assemblies mounted on the neutron shield tank. The neutron shield tank is a double-walled cylindrical structure that transfers the loadings to the heavy reinforced-concrete mat of the Containment structure. The tank also serves to minimize gamma and neutron heating of the primary concrete shield. UFSAR Section 5.3.1.2 discusses the design basis for the Containment ventilation systems. The ventilation systems were originally designed to limit the Containment bulk air temperature to below 105°F. Operating experience has demonstrated that the heat load in Containment exceeds the original design estimates but that the ventilation systems are adequate to maintain the Containment bulk air temperatures less than 125°F. The penetration cooling coils are managed for aging in the component cooling system (Section 2.3.3.8). The containment ventilation system is subject to Technical Specification limitations on containment bulk air temperature. Therefore, the aging effects due to elevated temperatures are not applicable for SPS, and a plant-specific aging management program is 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).

[3.5.1-005] [3.5.1-035] – The ASME Section XI, Subsection IWE program (B2.1.29) manages aging of the steel liner of the concrete Containment building. The 10 CFR Part 50, Appendix J program (B2.1.32) manages loss of leak tightness, loss of sealing, and leakage through Containment 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-specific operating experience associated with inaccessible areas from the ASME Section XI, Subsection IWE program (B2.1.29) has not identified any indications of corrosion. Operating experience associated with accessible areas from the ASME Section XI, Subsection IWE program (B2.1.29) has identified only minor indications of corrosion, which have been repaired by the corrective action program.

UFSAR Section 15.3.1 discusses concrete mix designs. Reinforced concrete structures at SPS 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. The mix proportions were established in accordance with ACI-301, “Specifications for Structural Concrete for Buildings.” The mix designs contain an air-entraining admixture capable of entraining three to five percent air in accordance with ASTM-C260, “Standard Specification for Air-Entraining Admixtures for Concrete” and maximum water content was controlled by placing the concrete at specified slumps. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The ASME Section XI, Subsection IWL program (B2.1.30) identifies and manages any cracks in the containment concrete that could potentially provide a pathway for water to reach inaccessible portions of the steel containment liner. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318-63, “Building Code Requirements for Reinforced Concrete.” Therefore, a plant-specific aging management program to manage the effects of general, pitting and crevice corrosion is not required.

(2) Loss of material due to general, pitting, and crevice corrosion could occur in steel torus shell of Mark I containments. The existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J, to manage this aging effect. If corrosion is significant, recoating of the torus is recommended. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable - BWR only.

(3) Loss of material due to general, pitting, and crevice corrosion could occur in steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and interior surface of suppression chamber shell of Mark III containments. The existing program relies on ASME Code Section XI, Subsection IWE to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is significant. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

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] – This aging effect is specific to prestressed concrete Containments and is not applicable to SPS.

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.

[3.5.1-009] – The evaluation of the SPS containment liner plate fatigue is addressed as a TLAA in SLRA Section 4.6.1, Containment Liner Plate.

There are no TLAAs for containment penetrations. The penetrations are designed for a one-time load due to the collapse of the connecting pipe. The normal operating loads are much smaller than the collapse loads of the pipe, including both restrained piping system thermal expansion loads, as well as local thermal expansion loads. The stresses due to the normal operating conditions are within the endurance limit. Therefore, the penetrations will not fail for a large number of operating cycles.

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 and10 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] – SPS does not have any stainless steel penetration bellows as part of the Containment pressure boundary. Stainless steel high energy pipes that penetrate the Containment are connected to carbon steel penetration sleeves with dissimilar metal welds. Plant operating experience has not identified any stress corrosion cracking associated with these welds. The ASME Section XI, Subsection IWE program (B2.1.29) and the 10 CFR Part 50, Appendix J program (B2.1.32) manage the aging of these dissimilar metal welds. Visual examinations are augmented with additional examinations, as necessary, to detect cracking in these welds. No augmented examinations have been required.

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 of this aging effect for plants located in moderate to severe weathering conditions.

[3.5.1-011] – SPS is located in a severe weathering region, as defined in ASTM C-33. UFSAR Section 15.3.1 discusses concrete mix designs. Reinforced concrete structures at SPS 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. The mix proportions were established in accordance with ACI 301, “Specifications for Structural Concrete for Buildings.” The mix designs contain an air-entraining admixture capable of entraining three to five percent air in accordance with ASTM-C260, “Standard Specification for Air-Entraining Admixtures for Concrete”, and maximum water content was controlled by placing the concrete at specified slumps. 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 program (B2.1.34) and the ASME Section XI, Subsection IWL program (B2.1.30) confirm the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, aging effects due to freeze-thaw in inaccessible areas are not applicable, and a plant-specific aging management program is not required.

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 if a plant-specific aging management program is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

[3.5.1-012] – Inspection for Alkali-Silica Reaction (ASR) has been incorporated into the ASME Section XI, Subsection IWL program (B2.1.30). Augmented inspections for the ASME Section XI, Subsection IWL program (B2.1.30) include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. ASR inspection results are evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of ASR development. Such indications will be entered into the Corrective Action program. Plant operating experience has not identified any indications of ASR.

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 if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

[3.5.1-014] – UFSAR Section 15.3.1 discusses concrete mix designs. Reinforced concrete structures at SPS 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. The mix proportions were established in accordance with ACI-301, “Specifications for Structural Concrete for Buildings.” Procedural controls ensured quality throughout the batching, mixing, and placement processes. The ASME Section XI, Subsection IWL program (B2.1.30) and the Structures Monitoring program (B2.1.34) identify and manage any cracks in the containment concrete. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI-318-63, "Building Code Requirements for Reinforced Concrete.” Plant operating experience has not identified any aging effects related to increase in porosity and permeability due to leaching of calcium hydroxide and carbonation. The Structures Monitoring program (B2.1.34) and the ASME Section XI, Subsection IWL program (B2.1.30) confirm the absence of aging effects related to leaching of calcium hydroxide and carbonation. Therefore, aging effects due to leaching of calcium hydroxide and carbonation are not applicable, and a plant-specific aging management program to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation is not required.

3.5.2.2.2.1 Aging Management of Inaccessible Areas

(1) Loss of material (palling, 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 this aging effect for inaccessible areas of these Groups of structures for plants located in moderate to severe weathering conditions.

[3.5.1-042] – Freeze-Thaw - UFSAR Section 15.3.1 discusses concrete mix designs. 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. The mix proportions were established in accordance with ACI-301, "Specifications for Structural Concrete for Buildings." The mix designs contain an air-entraining admixture capable of entraining three to five percent air in accordance with ASTM-C260, "Standard Specification for Air-Entraining Admixtures for Concrete", and maximum water content was controlled by placing the concrete at specified slumps. 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 program (B2.1.34) confirms the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, aging effects due to freeze-thaw are not applicable, and a plant-specific aging management program is not required.

(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 if a plant-specific AMP is required to manage this aging effect.

[3.5.1-043] – Alkali-Silica Reaction (ASR) - Inspection for ASR at SPS has been incorporated into the Structures Monitoring program (B2.1.34). This program includes identification of leading indicator structures to receive an augmented inspection each cycle of the Structures Monitoring program (B2.1.34). Augmented inspections include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. ASR inspection results are evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of ASR development. Such indications will be entered into the Corrective Action program. Plant operating experience has not identified any indications of ASR.

(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.

[3.5.1-044] [3.5.1-046] – Settlement - UFSAR Section 2.4.3.5 discusses allowable and measured site settlements. A site survey conducted in May 1975 indicated that site settlement was not a problem. A follow-up survey program was continued over the next two years to further monitor site elevations. The follow-up survey program indicated that a small amount of heave had occurred in the vicinity of both Containment structures; however, the differential movement between safety-related structures was below the allowable tolerance of 0.5 inches. The maximum differential movement for major structures on site had been about 0.2 inches. Inspection of structural interfaces showed no visible evidence of differential displacements. Accessible concrete components for in-scope structures are monitored by the Structures Monitoring program (B2.1.34) to confirm the absence of any visible effects due to settlement.

Porous concrete was not used at SPS, other than under the containment mat, which is evaluated above. Also, the dewatering system credited at SPS is only for the Containment, which is evaluated above.

(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 if leaching is observed in accessible areas that impact intended functions.

[3.5.1-047] – Leaching - UFSAR Section 15.3.1 discusses concrete mix designs. Reinforced concrete structures at SPS 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. The mix proportions were established in accordance with ACI-301, "Specifications for Structural Concrete for Buildings." Procedural controls ensured quality throughout the batching, mixing, and placement processes. The Structures Monitoring program (B2.1.34) identifies and manages any cracks in the concrete structures. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI-318-63, "Building Code Requirements for Reinforced Concrete." Plant operating experience has not identified any aging effects related to increase in porosity and permeability due to leaching of calcium hydroxide and carbonation. Therefore, a plant-specific aging management program to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation is 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°C (150°F) except for local areas, which are allowed to have increased temperatures not to exceed 93°C (200°F). Further evaluation is recommended of a plant-specific program if any portion of the safety-related and other concrete structures exceeds specified temperature limits [i.e., general area temperature greater than 66°C (150°F) and local area temperature greater than 93°C (200°F)]. 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 this SRP-SLR).

[3.5.1-048] – As discussed in UFSAR Section 9.5.1, the temperature of the fuel pool water is maintained below 140°F during the most limiting condition for normal core offload, which is a planned full core offload following refueling of the other unit. The temperature of the fuel pool water is maintained below 170°F during the most limiting condition for abnormal core offload, which is an unplanned full core offload following back-to-back refuelings of both units. The fuel pool water temperature is continuously indicated in the control room, and an alarm alerts the operator prior to this temperature reaching 140°F. Therefore, the concrete temperature will not exceed a temperature of 140°F except during the rare and short-term event of an abnormal core offload, during which the temperature of the concrete in some areas may reach 170°F. These concrete temperatures are below 150°F and 200°F, which are the code limits for general areas and local areas, respectively. The maximum general area air temperature in the Other Class I Structures is less than 150°F. The Main Steam Valve House has experienced a localized maximum temperature not greater than 160°F. Therefore, the concrete temperature has not exceeded a general area temperature greater than 150°F or a local area temperature greater than 200°F. Review of operating experience has identified no issues related to elevated temperatures affecting concrete structures. Therefore, a plant-specific aging management program to manage the effects of reduction of strength and modulus due to elevated temperature is 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 of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions.

[3.5.1-049] – UFSAR Section 15.3.1 discusses concrete mix designs. Reinforced concrete structures at SPS 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. The mix proportions were established in accordance with ACI-301, “Specifications for Structural Concrete for Buildings.” The mix designs contain an air-entraining admixture capable of entraining three to five percent air in accordance with ASTM-C260, “Standard Specification for Air-Entraining Admixtures for Concrete,” and maximum water content was controlled by placing the concrete at specified slumps. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The Structures Monitoring program (B2.1.34), which includes Group 6 structures, confirms the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Underwater inspections of water-control structures are periodically conducted using divers. Therefore, aging effects due to freeze-thaw are not applicable, and a plant-specific aging management program is not required.

(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 if a plant-specific AMP is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

[3.5.1-050] – Inspection for Alkali-Silica Reaction (ASR) at SPS has been incorporated into the Structures Monitoring program (B2.1.34), which includes Group 6 structures, which are addressed in the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program. This program includes identification of leading indicator structures to receive an augmented inspection each cycle of the Structures Monitoring program (B2.1.34). Augmented inspections include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. ASR inspection results are evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of ASR development. Such indications will be entered into the Corrective Action program.

(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 if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

[3.5.1-051] – UFSAR Section 15.3.1 discusses concrete mix designs. Reinforced concrete structures at SPS 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. The mix proportions were established in accordance with ACI-301, “Specifications for Structural Concrete for Buildings.” Procedural controls ensured quality throughout the batching, mixing, and placement processes. The Structures Monitoring program (B2.1.34), which includes Group 6 structures, identifies and manages any cracks in the concrete structures. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI-318-63, "Building Code Requirements for Reinforced Concrete.” Plant operating experience has not identified any aging effects related to increase in porosity and permeability due to leaching of calcium hydroxide and carbonation. Therefore, a plant-specific aging management program to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation is 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 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 that are within the scope of subsequent license renewal for SPS.

[3.5.1-099] – Plant-specific OE has identified pitting or crevice corrosion or cracking for stainless steel piping components exposed to air or condensation (see Further Evaluation 3.4.2.2.2). The ASME Section XI, Subsection IWF program (B2.1.31) 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 program (B2.1.31).

[3.5.1-100] – Plant-specific OE has identified pitting or crevice corrosion or cracking for stainless steel piping components exposed to air or condensation (see Further Evaluation 3.4.2.2.2). The Structures Monitoring program (B2.1.34) will manage the aging of stainless steel component supports and sump liners, and aluminum alloy component supports to ensure that these components continue to perform their intended functions during the subsequent period of extended operation.

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] – The evaluation of fatigue for component support members, anchor bolts, and welds for Group B1.1 components is addressed as a TLAA in SLRA Section 4.3.2, ASME Code, Section III, Class 1 Fatigue Analyses. The evaluation of fatigue for component support members, anchor bolts, and welds for Group B1.2 components are addressed as TLAAs in SLRA Section 4.3.3, ANSI B31.1 Allowable Stress Analyses.

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 1×10^{19} *neutrons/*cm^2 *neutron radiation and* 1×10^8 *Gy (*1×10^{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 of a plant-specific program to manage 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 or if plant specific OE of concrete irradiation degradation exists that may impact 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).

[3.5.1-097] – Surry Power Station is a three-loop pressurized water reactor plant in which the reactor pressure vessel (RPV) is surrounded by a water-filled neutron shield tank. The RPV is supported at each of the six nozzles by a support assembly. The bottom of each support assembly is supported by the top of the neutron shield tank. The neutron shield tank is constructed of two 1-1/2 inch thick steel shells separated by 34 inches of water. The weight of the RPV is carried by the neutron shield tank, and no vertical loads are transferred to the concrete biological shield (CBS) wall. The inner shell of the neutron shield tank extends continuously past the bottom of the reactor vessel to the basemat, where the vertical loads are transferred directly. Overturning moments and horizontal forces are resisted by the CBS wall through a layer of grout, which fills the 2 inch gap between the neutron shield tank and the CBS wall.

The maximum temperature on both the inside and outside surfaces of the CBS wall is 125°F. The maximum water temperature of the neutron shield tank is 125°F. The maximum fluence at the ID of the RPV is 7.71×10^{19} n/cm^2 (E > 1.0 MeV), determined by extrapolating surveillance program calculations to 80 years (72 EFPY).

EPRI Report 3002013051, “Irradiation Damage of the Concrete Biological Shield that Utilizes a Neutron Shield Tank: Basis for Concrete Biological Shield Wall for Aging Management,” addresses the effects of irradiation exposure and environmental temperature on the structural capability of the CBS wall at nuclear power plants with a neutron shield tank between the RPV and CBS wall. The specific example plant utilized for development of this report was SPS, with the modeling parameters such as neutron shield tank design configuration, operating temperatures, and RPV fluence levels described above. Therefore, the plant-specific values determined and conclusions reached for the example plant in the report are directly applicable to SPS. Using an evaluation period of 72 EFPY (80 years of operation), those values and conclusions are:

- The maximum neutron fluence at the CBS wall surface is 1.18 x 10^{13} n/cm^2 (E > 0.1 MeV). This value is substantially below the threshold value of 1.0 x 10^{19} n/cm^2 for E > 0.1 MeV.
- The estimated gamma surface dose at the CBS wall of 2.75 x 10^8 Rad is below the acceptability threshold of 1.0 x 10^{10} Rad.
- The maximum concrete temperature due to gamma heating is 125.1°F, which is approximately the same as the maximum ambient temperature of 125°F at the surface of the concrete and is below the acceptable long-term temperature limit of 200°F for local areas.

In addition to the above conclusions, no plant-specific OE of concrete irradiation degradation has been identified. Therefore, no additional thermal and structural analyses are required to establish the structural capability of the CBS wall, and no plant-specific aging management program to manage the effects of concrete irradiation is required.

3.5.2.2.3 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.

3.5.2.2.4 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

Intentionally Blank

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)	Consistent with NUREG-2191. 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)	Consistent with NUREG-2191.
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	Yes (SRP-SLR Section 3.5.2.2.1.2)	Not applicable. Temperature thresholds for reduction of strength and modulus of elasticity are not exceeded. 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)	Not applicable. SPS does not have prestressed Containment structures. The associated NUREG-2191 aging items are not used. 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. 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	Yes (SRP-SLR Section 3.5.2.2.1.7)	Not applicable. 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	Yes (SRP-SLR Section 3.5.2.2.1.8)	Consistent with NUREG-2191. The plant specific aging management program used to manage cracking of Containment concrete elements (inaccessible areas) is ASME Section XI, Subsection IWL (B2.1.30) 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	Yes (SRP-SLR Section 3.5.2.2.1.9)	Not applicable. 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 Containment concrete elements (accessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) 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 due to freeze-thaw of Containment concrete is managed by the ASME Section XI, Subsection IWL (B2.1.30) program.
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 Containment concrete elements (accessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) 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
3.5.1-020	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	Not applicable. See further evaluation in Section 3.5.2.2.1.9.
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 Containment concrete elements (accessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) 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 Containment concrete elements (inaccessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) program and the Structures Monitoring (B2.1.34) 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 Containment concrete elements (inaccessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) program and the Structures Monitoring (B2.1.34) program.
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.

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
3.5.1-027	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	No	Consistent with NUREG-2191. In addition to Containment Structure, components in Auxiliary Systems (Fuel Handling) are aligned to this item.
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.
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	Not applicable. SPS does not have prestressed Containment structures. The associated NUREG-2191 aging items are not used.
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.

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
3.5.1-034	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. 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.
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.

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
3.5.1-040	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	No	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	Yes (SRP-SLR Section 3.5.2.2.2.1.1)	Not applicable. 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	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 (B2.1.34) 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.
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 other than Containment. 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
3.5.1-047	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	Yes (SRP-SLR Section 3.5.2.2.2.1.4)	Not applicable 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	Yes (SRP-SLR Section 3.5.2.2.2.2)	Not applicable. 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	Yes (SRP-SLR Section 3.5.2.2.2.3.1)	Not applicable. 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	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 (B2.1.34) program for the Discharge Tunnel & Seal Pit, High Level Intake Structure, and Low Level Intake Structure and the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program for the Discharge Canal and Intake Canal. See further evaluation in Section 3.5.2.2.2.3.2.
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	Yes (SRP-SLR Section 3.5.2.2.2.3.3)	Not applicable. See further evaluation in Section 3.5.2.2.2.3.3.

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
3.5.1-052	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)	Not applicable. 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)	Consistent with NUREG-2191. Cumulative fatigue damage of bolting and steel elements is a TLAA. 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.
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 exposed to water-flowing is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (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
3.5.1-057	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.
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 dike and embankment is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) 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) is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.
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 due to freeze-thaw of group 6 concrete elements (accessible areas) is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (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
3.5.1-061	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.
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	Consistent with NUREG-2191, however, a different aging management program (the Structures Monitoring (B2.1.34) program) is credited.
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.
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. For those components credited with a fire barrier function, the Fire Protection Program (B2.1.15) is used in conjunction with the Structures Monitoring Program (B2.1.34) to manage loss of sealing.
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.

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. For those components credited with a fire barrier function, the Fire Protection Program (B2.1.15) is used in conjunction with the Structures Monitoring Program (B2.1.34) to manage loss of material.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. Monitoring of the spent fuel pool water level and leakage from the leak chase channels is performed by the Structures Monitoring (B2.1.34) program.
3.5.1-079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
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.
3.5.1-082	Structural bolting	Loss of material due to general, pitting, crevice 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
3.5.1-083	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. Loss of material of structural bolting and steel elements is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.
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. SPS has no in-scope stainless steel structural bolting exposed to treated water 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. SPS has no in-scope steel structural bolting exposed to air-outdoor that is managed by the ASME Section XI, Subsection IWF (B2.1.30) program. 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.
3.5.1-088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191 with a different program assigned for bolting associated with the cranes and hoists system. In addition to Structures and Component Supports, stainless steel components in Auxiliary Systems (cranes and hoists) are aligned to this item. Loss of preload of stainless steel bolting in Auxiliary Systems (cranes and hoists) will be managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13) program.
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.

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
3.5.1-090	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. SPS has no in-scope steel or stainless steel support members, welds, bolted connections or support anchorage to building structures submerged in treated water 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.
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.
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 items for Steel. 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 for components within the scope of Structures Monitoring program. Not applicable for components within the scope of IWF. There are no non-metallic vibration isolation elements within the scope of the IWF program at SPS.
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 items for Steel. The associated NUREG-2191 aging items are not used.

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
3.5.1-096	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	Yes (SRP-SLR Section 3.5.2.2.2.6)	Not applicable. See further evaluation in Section 3.5.2.2.2.6.
3.5.1-098	Stainless steel, aluminum alloy support members; welds; bolted connections; support anchorage to building structure	None	None	No	Consistent with NUREG-2191.
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 for stainless steel support components. There are no aluminum support components that are within the scope of the ASME Section XI, Subsection IWF(B2.1.31) program. 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. See further evaluation in Section 3.5.2.2.2.4.

Intentionally Blank

Results Tables: Containment, Structures and Component Supports AMR Results

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - 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	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-148	3.5.1-031	A
					Structures Monitoring (B2.1.34)	III.A4.TP-248	3.5.1-080	A
						III.A7.TP-248	3.5.1-080	A
						III.A8.TP-248	3.5.1-080	A
				Loss of preload	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-150	3.5.1-030	A
					Structures Monitoring (B2.1.34)	III.A4.TP-261	3.5.1-088	A
						III.A7.TP-261	3.5.1-088	A
						III.A8.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-148	3.5.1-031	A
					Structures Monitoring (B2.1.34)	III.A7.TP-248	3.5.1-080	A
						III.A8.TP-248	3.5.1-080	A
						III.A1.TP-274	3.5.1-082	A
						III.A7.TP-274	3.5.1-082	A
						III.A8.TP-274	3.5.1-082	A
				Loss of preload	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-150	3.5.1-030	A
					Structures Monitoring (B2.1.34)	III.A1.TP-261	3.5.1-088	A
						III.A7.TP-261	3.5.1-088	A
						III.A8.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;PB	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-40	3.5.1-026	A
					10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-41	3.5.1-033	A
			(E) Air – outdoor	Loss of sealing	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-41	3.5.1-033	A
Concrete blocks (shielding)	EN	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A1.T-12	3.5.1-070	A

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - 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 (B2.1.34)	III.A1.TP-204	3.5.1-043	E, 1, 2, 7
						III.A4.TP-25	3.5.1-054	A, 1, 6
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A4.TP-26	3.5.1-066	A, 1, 6
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A4.TP-28	3.5.1-067	A, 1, 7
			(E) Air – outdoor	Cracking	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-67	3.5.1-012	E, 1, 4, 7
						II.A1.CP-33	3.5.1-019	A, 1, 6
				Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-68	3.5.1-021	A, 1, 6
						II.A1.CP-97	3.5.1-023	A, 1, 7
					Structures Monitoring (B2.1.34)	II.A1.CP-97	3.5.1-023	A, 1, 7
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-87	3.5.1-016	A, 1, 6
						II.A1.CP-100	3.5.1-024	A, 1, 6
					Structures Monitoring (B2.1.34)	II.A1.CP-100	3.5.1-024	A, 1, 6
				Loss of material (spalling, scaling) and cracking	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-31	3.5.1-018	A, 1, 6

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - 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	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-67	3.5.1-012	E, 1, 4, 7
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-100	3.5.1-024	A, 1, 6
					Structures Monitoring (B2.1.34)	II.A1.CP-100	3.5.1-024	A, 1, 6
			(E) Soil	Cracking	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-67	3.5.1-012	E, 1, 4, 7
				Cracking and distortion	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-101	3.5.1-001	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-101	3.5.1-001	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-97	3.5.1-023	A, 1, 7
					Structures Monitoring (B2.1.34)	II.A1.CP-97	3.5.1-023	A, 1, 7
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-100	3.5.1-024	A, 1, 6
					Structures Monitoring (B2.1.34)	II.A1.CP-100	3.5.1-024	A, 1, 6
			(E) Water – flowing	Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-97	3.5.1-023	A, 1, 7
					Structures Monitoring (B2.1.34)	II.A1.CP-97	3.5.1-023	A, 1, 7
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	II.A1.C-07	3.5.1-002	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	ASME Section XI, Subsection IWL (B2.1.30)	VII.G.A-90	3.3.1-060	E, 1
					Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - 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 missile barrier	EN;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A7.TP-25	3.5.1-054	A, 6
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A7.TP-26	3.5.1-066	A, 6
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A7.TP-28	3.5.1-067	A, 7
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A7.TP-25	3.5.1-054	A, 6
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A7.TP-26	3.5.1-066	A, 6
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A7.TP-28	3.5.1-067	A, 7
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
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A1.CP-98	3.5.1-005	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A1.CP-98	3.5.1-005	A
					10 CFR Part 50, Appendix J (B2.1.32)	II.A1.CP-35	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A1.CP-35	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
Containment sump liner	PB;SS	Stainless steel	(E) Water – standing	Cracking; loss of material	One-Time Inspection (B2.1.20)	III.A7.T-23	3.5.1-052	E, 5
Door locking mechanism	PB;SS	Steel	(E) Air – indoor uncontrolled	Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
			(E) Air – outdoor	Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	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
Embedded steel	SS	Steel	(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	C

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Equipment hatch	PB;SS;EN;MB	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	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 (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	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
Equipment hatch air lock doors	PB;SS;EN;MB	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	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 (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	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

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fuel transfer tube enclosure protection shield	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A1.TP-302	3.5.1-077	A
Grout	SS	Concrete	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	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
		Grout	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B1.1.TP-42	3.5.1-055	A
						III.B1.2.TP-42	3.5.1-055	A
			(E) Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B3.TP-42	3.5.1-055	A
						III.B5.TP-42	3.5.1-055	A
Hinges and pins	PB;SS	Steel	(E) Air – indoor uncontrolled	Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
			(E) Air – outdoor	Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	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
O-rings	PB;SS	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-41	3.5.1-033	A
Penetrations (electrical)	PB;SS	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	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 Containments, Structures and Component Supports - Containment - 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)	SS;EN;PB	Dissimilar metal welds	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	A
		Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	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
Personnel hatch	PB;SS;EN	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	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 (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	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
Porous concrete	SS	Porous concrete	(E) Water – flowing	Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	II.A1.C-07	3.5.1-002	A
Reactor cavity liner	PB;SS	Stainless steel	(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	B
Reactor cavity seal ring	PB;SS	Stainless steel	(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	B
Service Level I coatings	MCI	Coatings	(E) Air – indoor uncontrolled	Loss of coating or lining integrity	Protective Coating Monitoring and Maintenance (B2.1.36)	II.A3.CP-152	3.5.1-034	A
						III.A4.TP-301	3.5.1-073	A

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - 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	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A4.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A1.TP-302	3.5.1-077	A, 3
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 3
Steel missile shields	SS;MB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A8.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
Waterproofing membrane	EN;FLB	Elastomer, rubber and other similar materials	(E) Groundwater	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Soil	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-1 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, foundations, and pads.
2. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
3. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, doors, ventilation dome opening hatch covers, and embedded steel.
4. 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 IWL (B2.1.30) program.
5. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the One-Time Inspection (B2.1.20) program.
6. This line is used for components in accessible areas.
7. This line is used for components in inaccessible areas.

Table 3.5.2-2 Containments, Structures and Component Supports - Auxiliary Building 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) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	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	C
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 3, 5
						III.A3.TP-25	3.5.1-054	A, 1, 4
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 3, 5
						III.A3.TP-25	3.5.1-054	A, 1, 4
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1

Table 3.5.2-2 Containments, Structures and Component Supports - Auxiliary Building 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; MB;SS	Concrete Reinforced concrete	(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 3, 5
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 3, 5
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
			(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Concrete hatches	EN;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 3, 5
						III.A3.TP-25	3.5.1-054	A, 4
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A

Table 3.5.2-2 Containments, Structures and Component Supports - Auxiliary Building 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
Doors	FB;MB;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	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	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
Embedded steel	SS	Steel	(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	C
Masonry block walls	SS;EN;FB	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	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 (B2.1.33)	VII.G.A-626	3.3.1-179	A
Metal siding walls	SS;EN;FB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;LB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	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
Steel hatches	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	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

Table 3.5.2-2 Containments, Structures and Component Supports - Auxiliary Building 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 missile shields	SS;EN;MB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	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

Table 3.5.2-2 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, and hatches.
2. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, doors, sampling panels, and embedded steel.
3. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
4. This line is used for components in accessible areas.
5. This line is used for components in inaccessible areas.

Table 3.5.2-3 Containments, Structures and Component Supports - Discharge Canal - 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	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
						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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 2
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 2
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 2
			(E) Groundwater	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 2
			(E) Soil	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 2

Table 3.5.2-3 Containments, Structures and Component Supports - Discharge Canal - 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) Water – flowing	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
						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 (B2.1.35)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 2
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 2
Earthen dike and embankment	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 (B2.1.35)	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 (B2.1.35)	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 (B2.1.35)	III.A6.T-22	3.5.1-058	A

Table 3.5.2-3 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Inspection of Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.

2. Concrete elements include slabs, curbs, foundations, and liners.

Table 3.5.2-4 Containments, Structures and Component Supports - Intake Canal - 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 – outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
						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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 2
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 2
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 2
			(E) Groundwater	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 2
			(E) Soil	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 2

Table 3.5.2-4 Containments, Structures and Component Supports - Intake Canal - 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) Water – flowing	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-220	3.5.1-050	E, 1, 2
						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 (B2.1.35)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 2
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 2
Earthen dike and embankment	SS;SCW	Earthfill (rip-rap, stone, soil)	(E) Air – outdoor	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	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 (B2.1.35)	III.A6.T-22	3.5.1-058	A

Table 3.5.2-4 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Inspection of Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.
2. Concrete elements include slabs, curbs, foundations, and liners.

Table 3.5.2-5 Containments, Structures and Component Supports - Fuel Building 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	Stainless steel	(E) Air with borated water leakage	None	None	III.B1.2.TP-4	3.5.1-098	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A5.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-248	3.5.1-080	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
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	E, 1, 4
						III.A5.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	E, 1, 4
						III.A5.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A5.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-212	3.5.1-065	A, 1
						III.A5.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-29	3.5.1-067	A, 1

Table 3.5.2-5 Containments, Structures and Component Supports - Fuel Building 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;FLB;MB; SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	E, 1, 4
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A5.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-212	3.5.1-065	A, 1
						III.A5.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	E, 1, 4
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A5.TP-31	3.5.1-046	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A5.T-12	3.5.1-070	A
Metal siding	EN	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-302	3.5.1-077	A, 5
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-302	3.5.1-077	A, 5
Pipe piles	SS	Steel	(E) Groundwater	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
			(E) Soil	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Spent fuel pool liner plates	PB;SS;EN	Stainless steel	(E) Air with borated water leakage	None	None	III.B1.2.TP-4	3.5.1-098	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	C
			(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	B

Table 3.5.2-5 Containments, Structures and Component Supports - Fuel Building 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
Stainless steel elements	SS;EN	Stainless steel	(E) Air with borated water leakage	None	None	III.B1.2.TP-4	3.5.1-098	A, 3
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	C, 3
			(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A5.T-14	3.5.1-078	C, 3
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	D, 3
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A5.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
			(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	C, 2
Steel gates or doors	EN;PB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-302	3.5.1-077	A

Table 3.5.2-5 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, hatches, and dikes.
2. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, and embedded steel.
3. Stainless steel elements include spent fuel storage racks, and cask pads.
4. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
5. Metal siding includes blow-off panels.

Table 3.5.2-6 Containments, Structures and Component Supports - Discharge Tunnel and Seal Pit - 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	BWI	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 2
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 2
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 2
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 2
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 2

Table 3.5.2-6 Containments, Structures and Component Supports - Discharge Tunnel and Seal Pit - 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	BWI	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 2
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 2
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 2
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.TP-31	3.5.1-046	A, 2

Table 3.5.2-6 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include slabs, curbs, foundations, and liner.

Table 3.5.2-7 Containments, Structures and Component Supports - High Level 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) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
Concrete elements	BWI;FB;MB; SCW;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1

Table 3.5.2-7 Containments, Structures and Component Supports - High Level 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	BWI;FB;MB; SCW;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 1
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1

Table 3.5.2-7 Containments, Structures and Component Supports - High Level 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	BWI;FB;MB; SCW;SS	Concrete	(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.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 (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Gaskets (seal plates)	FLB	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Water – flowing	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Masonry block walls	SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A6.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A6.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	III.A6.TP-34	3.5.1-071	A

Table 3.5.2-7 Containments, Structures and Component Supports - High Level 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	FLB;FLT; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 3
			(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	C, 3
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 3

Table 3.5.2-7 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, and missile barriers.
2. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
3. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, doors, trusses, embedded steel, missile shields over low level probe and cable, seal plates, and trash racks.

Table 3.5.2-8 Containments, Structures and Component Supports - Low Level 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) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
Concrete elements	BWI;FB;FLB; MB;SCW;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1

Table 3.5.2-8 Containments, Structures and Component Supports - Low Level 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	BWI;FB;FLB; MB;SCW;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	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 (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 1
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1

Table 3.5.2-8 Containments, Structures and Component Supports - Low Level 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	BWI;FB;FLB; MB;SCW;SS	Concrete	(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	E, 1, 2
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.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 (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Gaskets (gate seals)	FLB	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Water – flowing	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Masonry block walls	SS;FB	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A6.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A6.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	III.A6.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 (B2.1.33)	VII.G.A-626	3.3.1-179	A

Table 3.5.2-8 Containments, Structures and Component Supports - Low Level 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	FLB;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 3
			(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	C, 3
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	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 (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 3
Trash racks	FLT	Fiberglass	(E) Raw water	Cracking, blistering, lack of material; flow blockage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	VII.C1.AP-238	3.3.1-030a	E, 4, 5
		HDPE	(E) Raw water	Cracking, blistering, lack of material; flow blockage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	VII.C1.AP-239	3.3.1-030a	E, 4, 5

Table 3.5.2-8 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, and louver missile shields.

2. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

3. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, trusses, embedded steel, louvers, missile shields for louvers, doors, gates, and watertight wells.

4. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for trash racks.

5. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program is used to manage aging of HDPE and Fiberglass trash rack components.

Table 3.5.2-9 Containments, Structures and Component Supports - Black Battery 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-9 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include foundation, pads and curbs.
3. Steel elements include beams, columns, baseplates, bracing, doors, wall panels and roofing.

Table 3.5.2-10 Containments, Structures and Component Supports - Central Alarm Station - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-10 Containments, Structures and Component Supports - Central Alarm Station - 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	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-10 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include foundation, walls, pads, and curbs.

3. Steel elements include beams, columns, baseplates, bracing, doors, wall panels, and roofing.

Table 3.5.2-11 Containments, Structures and Component Supports - Condensate Polishing 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A

Table 3.5.2-11 Containments, Structures and Component Supports - Condensate Polishing 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
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-11 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include foundation, floor slabs, pads, and curbs.
3. Steel elements include beams, columns, baseplates, bracing, doors, wall panels, stairways, ladders, railings, and roofing.

Table 3.5.2-12 Containments, Structures and Component Supports - Laundry Facility - 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 (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 3
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 3
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-12 Containments, Structures and Component Supports - Laundry Facility - 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	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 3
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	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 (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-12 Plant-Specific Notes:

1. Concrete elements include foundation, floor slabs, roof slabs.
2. Steel elements include beams, support members, and doors.
3. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

Table 3.5.2-13 Containments, Structures and Component Supports - Machine Shop - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A

Table 3.5.2-13 Containments, Structures and Component Supports - Machine Shop - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-13 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include foundation, floor slabs, curbs, and pads.
3. Steel elements include beams, columns, baseplates, bracing, wall panels, louvers, doors, stairways, railings, and roofing.

Table 3.5.2-14 Containments, Structures and Component Supports - Radwaste Facility - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-14 Containments, Structures and Component Supports - Radwaste Facility - 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	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-14 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include foundation, floor slabs, pads, curbs, hatches, interior and exterior walls.
3. Steel elements include beams, columns, baseplates, bracing, doors, flooring, wall panels, platforms, hatches, stairways, ladders, railings, and roofing.

Table 3.5.2-15 Containments, Structures and Component Supports - SBO 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-15 Containments, Structures and Component Supports - SBO 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	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-15 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include foundation, walls, ceiling slabs, pads, curbs, and roofing slabs and pavers.

3. Steel elements include beams, columns, baseplates, bracing, doors, flooring, wall panels and louvers, platforms, stairways, ladders, railings, and roofing.

Table 3.5.2-16 Containments, Structures and Component Supports - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB; MB;PB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-16 Containments, Structures and Component Supports - 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;FB;FLB; MB;PB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	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 (B2.1.34)	VII.G.A-90	3.3.1-060	A, 2
Doors	EN;FB;FLB; MB;PB	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 (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Flood dikes	FLB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	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 (B2.1.33)	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 (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;LB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-16 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the SStructures Monitoring (B2.1.34) program.

2. Concrete elements include foundation, walls, floor slabs, hatches, pads, curbs, and roofing slabs.

3. Steel elements include beams, columns, baseplates, bracing, flooring, wall panels and louvers, platforms, stairways, ladders, railings, sampling panels, and roofing.

Table 3.5.2-17 Containments, 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
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB; MB;PB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-17 Containments, 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;FLB; MB;PB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	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 (B2.1.34)	VII.G.A-90	3.3.1-060	A, 2
Doors	EN;FB;FLB; MB;PB	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 (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Flood dikes	FLB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	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 (B2.1.33)	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 (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-17 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include foundation, walls, floor slabs, hatches, pads, curbs.

3. Steel elements include beams, columns, baseplates, bracing, flooring, wall panels and louvers, missile shields, platforms, stairways, ladders, railings, and roofing.

Table 3.5.2-18 Containments, Structures and Component Supports - Containment Spray Pump 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;SS	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 4
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;MB; SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-18 Containments, Structures and Component Supports - Containment Spray Pump 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;MB; SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-18 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, hatches, and dikes.
3. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, doors, and embedded steel.
4. Aluminum elements include the roof hatch cover and fixed louvers.

Table 3.5.2-19 Containments, Structures and Component Supports - Fire Pump House - 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 (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 4
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	FB;FLB;MB; SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-19 Containments, Structures and Component Supports - Fire Pump House - 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	FB;FLB;MB; SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
Masonry block	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	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 (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-19 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include walls, slabs, curbs, foundations, pads, and dikes.
3. Steel elements include beams, decking, doors, missile shields, and embedded steel.
4. Aluminum elements include fixed louvers.

Table 3.5.2-20 Containments, Structures and Component Supports - Fuel Oil Pump House - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 1, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-20 Containments, Structures and Component Supports - Fuel Oil Pump House - 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 (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
Masonry block walls	EN;FLB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	III.A3.TP-34	3.5.1-071	A
Steel elements	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-20 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, hatches, concrete missile shields, and manholes.
3. Steel elements include beams, stairs, platforms, grating, ladders, doors, and embedded steel.

Table 3.5.2-21 Containments, Structures and Component Supports - Main Steam Valve House - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	SS;EN;FB; MB;JIS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 1, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 1, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1, 2
						III.A3.TP-27	3.5.1-065	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-21 Containments, Structures and Component Supports - Main Steam Valve House - 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;EN;FB; MB;JIS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
Pipe piles	SS	Steel	(E) Groundwater	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
			(E) Soil	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-21 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, hatches, concrete missile shields, manholes, and dikes.
3. Steel elements include beams, columns, plates, bracing, trusses, stairs, platforms, grating, decking, ladders, doors, and embedded steel.

Table 3.5.2-22 Containments, Structures and Component Supports - Safeguards 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-22 Containments, Structures and Component Supports - Safeguards 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	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
Pipe piles	SS	Steel	(E) Groundwater	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
			(E) Soil	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-22 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, hatches, concrete missile shields, and dikes.
3. Steel elements include beams, columns, plates, bracing, stairs, platforms, grating, decking, ladders, doors, and embedded steel.

Table 3.5.2-23 Containments, Structures and Component Supports - Buried Fuel Oil Tank Missile Barrier - 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 element	SS;MB	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-23 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete element includes the missile barrier.

Table 3.5.2-24 Containments, Structures and Component Supports - Chemical Addition Tank Foundation - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Grout	SS	Grout	(E) Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B4.TP-42	3.5.1-055	A

Table 3.5.2-24 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include the footing, the pump support, and the pedestal.

Table 3.5.2-25 Containments, 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 (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Pull boxes	EN	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-25 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include the duct banks, cable trenches, and transition boxes.

Table 3.5.2-26 Containments, Structures and Component Supports - Emergency Condensate Tank Foundations and Missile Barriers - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Compressible seal	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Concrete elements	EN;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-26 Containments, Structures and Component Supports - Emergency Condensate Tank Foundations and Missile Barriers - 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	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-26 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include the foundations, the walls, the roof slabs, the hatches, and the piping enclosure.

Table 3.5.2-27 Containments, Structures and Component Supports - Fire Protection and Domestic Water Tank Foundation - 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 element	SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-27 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete element includes the ring wall.

Table 3.5.2-28 Containments, Structures and Component Supports - Fuel Oil Line Missile Barrier - 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 – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Steel element	EN;SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-28 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include the missile barrier slabs and the spread footings.
3. Steel element includes the support plate.

Table 3.5.2-29 Containments, Structures and Component Supports - Fuel Oil Storage Tank Dike - 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	FLB;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-29 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include the footings and the walls.

Table 3.5.2-30 Containments, Structures and Component Supports - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-30 Containments, Structures and Component Supports - 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
Steel elements	SS;MB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-30 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include the manhole structures.
3. Steel elements include the manhole covers, ladders, and platforms.

Table 3.5.2-31 Containments, Structures and Component Supports - Reactor Containment Subsurface Drainage System Access Shaft - 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 (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-31 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include the walls and floor of the shaft.

Table 3.5.2-32 Containments, Structures and Component Supports - Refueling Water Storage Tank Foundation - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	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	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Concrete element	SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Grout	SS	Grout	(E) Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B4.TP-42	3.5.1-055	A

Table 3.5.2-32 Containments, Structures and Component Supports - Refueling Water Storage Tank Foundation - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pipe piles	SS	Steel	(E) Groundwater	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
			(E) Soil	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A

Table 3.5.2-32 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete element includes the foundation mat.

Table 3.5.2-33 Containments, Structures and Component Supports - SBO Structures for Offsite Power - 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 (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-33 Containments, Structures and Component Supports - SBO Structures for Offsite Power - 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	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
Concrete masonry walls	SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	III.A3.TP-34	3.5.1-071	A
Steel elements	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
Wooden poles	SS	Wood	(E) Air – outdoor	Loss of material; change in material properties	Structures Monitoring (B2.1.34)	III.A6.TP-223	3.5.1-062	E, 4
			(E) Groundwater	Loss of material; change in material properties	Structures Monitoring (B2.1.34)	III.A6.TP-223	3.5.1-062	E, 4
			(E) Soil	Loss of material; change in material properties	Structures Monitoring (B2.1.34)	III.A6.TP-223	3.5.1-062	E, 4

Table 3.5.2-33 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include the foundations, walls, and footings.
3. Steel elements include miscellaneous steel supporting the breakers, disconnects, and transformers, roof framing and decking, and power poles.
4. The Structures Monitoring (B2.1.34) program is used instead of Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program to manage the applicable aging effect(s) for this component type, material, and environment combination.

Table 3.5.2-34 Containments, Structures and Component Supports - Security Lighting Poles - 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 (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-34 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.

2. Concrete elements include the lighting poles.

Table 3.5.2-35 Containments, Structures and Component Supports - Transformer Firewalls and Dikes - 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	FB;FLB;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
						III.A3.TP-25	3.5.1-054	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 2
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 2
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	E, 1, 2
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 2
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 2

Table 3.5.2-35 Plant-Specific Notes:

1. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
2. Concrete elements include the walls, dikes, and the spread footings.

Table 3.5.2-36 Containments, 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 (B2.1.34)	III.B2.T-37b	3.5.1-100	A, 2
						III.B3.T-37b	3.5.1-100	A, 2
						III.B4.T-37b	3.5.1-100	A, 2
						III.B5.T-37b	3.5.1-100	A, 2
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	III.B1.2.T-26	3.5.1-053	A
				Loss of material	Structures Monitoring (B2.1.34)	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 (B2.1.31)	III.B1.2.TP-226	3.5.1-081	A
						III.B1.2.T-24	3.5.1-091	A
					Structures Monitoring (B2.1.34)	III.B2.TP-43	3.5.1-092	A
						III.B3.TP-43	3.5.1-092	A
						III.B4.TP-43	3.5.1-092	A
						III.B5.TP-43	3.5.1-092	A
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.TP-229	3.5.1-087	A
					Structures Monitoring (B2.1.34)	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
						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
						III.B5.T-25	3.5.1-089	A

Table 3.5.2-36 Containments, 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
Grout	SS	Grout	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	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 (B2.1.34)	III.B2.TP-46	3.5.1-074	A
Spring support	SS	Steel	(E) Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-28	3.5.1-057	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B2.T-25	3.5.1-089	A
Stainless steel elements	SS	Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-36b	3.5.1-099	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	III.B1.2.T-26	3.5.1-053	A, 1
				Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-24	3.5.1-091	A, 1
					Structures Monitoring (B2.1.34)	III.B2.TP-43	3.5.1-092	A, 1
						III.B3.TP-43	3.5.1-092	A, 1
						III.B4.TP-43	3.5.1-092	A, 1
						III.B5.TP-43	3.5.1-092	A, 1
			(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, 1
						III.B2.T-25	3.5.1-089	A, 1
						III.B3.T-25	3.5.1-089	A, 1
						III.B4.T-25	3.5.1-089	A, 1
						III.B5.T-25	3.5.1-089	A, 1
Vibration isolation elements	SS	Non-metallic (e.g., rubber)	(E) Air – indoor uncontrolled	Reduction or loss of isolation function	Structures Monitoring (B2.1.34)	III.B4.TP-44	3.5.1-094	A

Table 3.5.2-36 Plant-Specific Notes:

1. Steel elements include support members, bearing plates, base plates, connections, cable trays, conduits, instrument racks, and structural frames.
2. Aluminum elements include support members, cable trays, and conduits.

Table 3.5.2-37 Containments, 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 (B2.1.34)	III.B3.TP-248	3.5.1-080	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-248	3.5.1-080	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;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-43	3.5.1-092	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	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	A
Fire barrier seals	FB	Cerafiber, pyrocrete, micarta, dux seal, KBS sealbags, mineral wool, gypsum	(E) Air – indoor uncontrolled	Loss of material, change in material properties, cracking/delamination, separation	Fire Protection (B2.1.15)	None	None	E, 2
		Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	A
Fire stops	FB	Cera fiber, cera blanket, marinite board	(E) Air – indoor uncontrolled	Loss of material, change in material properties, cracking/delamination, separation	Fire Protection (B2.1.15)	None	None	J
Fire wraps and coatings	FB	3M Interam, pyrocrete, bio-fire (bio K-10 mortar)	(E) Air – indoor uncontrolled	Loss of material, change in material properties, cracking/delamination, separation	Fire Protection (B2.1.15)	None	None	J
Penetration seals	EN;PB	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Groundwater	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Soil	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-37 Containments, 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 sleeves	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-43	3.5.1-092	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	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	A
			(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	C
Radiant energy shields	FB	Stainless steel	(E) Air	Loss of material; cracking	Fire Protection (B2.1.15)	III.B2.T-37b	3.5.1-100	E, 2
		Thermo-lag, marinite	(E) Air – indoor uncontrolled	Loss of material, change in material properties, cracking/delamination	Fire Protection (B2.1.15)	None	None	J
Seismic gap covers	EN;FB	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	A
				Loss of material; cracking; hardening; loss of strength; shrinkage	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	C
		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 (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
		Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	C
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Seismic gap filler material	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-37 Plant-Specific Notes:

1. The Fire Protection (B2.1.15) program is used in conjunction with the Structures Monitoring (B2.1.34) program to manage the applicable aging effect(s) for this component type, material, and environment combination.

2. The Fire Protection (B2.1.15) program is used instead of the Structures Monitoring (B2.1.34) program to manage the applicable aging effect(s) for this component type, material, and environment combination.

Table 3.5.2-38 Containments, 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 (B2.1.31)	III.B1.1.TP-41	3.5.1-068	A
		Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.T-36b	3.5.1-099	A
			(E) Air with borated water leakage	None	None	III.B1.1.TP-4	3.5.1-098	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-226	3.5.1-081	A
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-229	3.5.1-087	A
			(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 (B2.1.34)	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 (B2.1.31)	III.B1.1.TP-45	3.5.1-075	A
Stainless steel elements	SS	Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.T-36b	3.5.1-099	A, 2
			(E) Air with borated water leakage	None	None	III.B1.1.TP-4	3.5.1-098	A, 2
Steel elements	SS	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	III.B1.1.T-26	3.5.1-053	A, 1
				Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.T-24	3.5.1-091	A, 1
				Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.T-28	3.5.1-057	A, 1
			(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, 1

Table 3.5.2-38 Plant-Specific Notes:

1. Steel elements include support members, spring supports, bearing plates, base plates, and connections, including maraging steel.
2. Stainless steel elements include support members.

Tables 3.5.2-1 through 3.5.2-38 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.

Intentionally Blank

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.

- Cables and Connections (Section 2.5.1.1)
- High Voltage Insulators (Section 2.5.1.2)
- Metal Enclosed Bus (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 - Cables and Connections - Aging Management Evaluation
- Table 3.6.2-2, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation
- Table 3.6.2-3, Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation

3.6.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.6.2.1.1 Cables and Connections

Materials

The materials of construction for the cables and connections subcomponents are:

- Aluminum
- Electrical insulation: bakelite; phenolic melamine or ceramic; molded polycarbonate; other
- Stainless 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
- 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 (B2.1.43)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.37)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B2.1.38)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.40)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.41)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.39)

3.6.2.1.2 High Voltage Insulators

Materials

The materials of construction for the high voltage insulators subcomponents are:

- Aluminum
- Cement
- Galvanized steel
- Malleable iron
- 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 (B2.1.44)

3.6.2.1.3 Metal Enclosed Bus

Materials

The materials of construction for the metal enclosed bus subcomponents are:

- Aluminum
- Elastomer
- Porcelain
- Steel
- Thermo-plastic organic polymers
- Various metals used for electrical bus and connections
- Xenoy

Environment

The metal enclosed bus subcomponents are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects, associated with the metal enclosed bus subcomponents, require management:

- Increased electrical resistance of connection
- Loss of material
- Reduced electrical insulation resistance
- Surface cracking, crazing, scuffing, dimensional change, shrinkage, discoloration, hardening, loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the metal enclosed bus subcomponents:

- Metal-Enclosed Bus (B2.1.42)

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

[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

[3.6.1-029] [3.6.1-030] [3.6.1-031] - Reduced insulation resistance and loss of material for cable bus can be caused by age related degradation. This issue is not applicable because SPS does not use cable bus.

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 switchyard bus, bus connections, transmission conductors and connections are those credited for recovery of offsite power following a station blackout event. Overhead cables credited for recovery of offsite power following a station blackout event operate at distribution voltage (34.5 kV) instead of transmission voltage (>69 kV), and would typically be referred to as overhead conductors and overhead conductor connections. However, for consistency in terminology, they will be referred to as transmission conductors and transmission connections.

[3.6.1-004] - SPS has no in-scope ACSR transmission conductors in the Transmission Conductor component group. The in-scope transmission conductors at SPS are bare 477 kcmil All Aluminum Conductor, 19 strand conductors and are not subject to corrosion that requires aging management.

[3.6.1-005] - Increased electrical resistance of connection due to oxidation or loss of pre-load is not applicable for aluminum transmission connectors exposed to outdoor air environments in the Transmission Connections component group at SPS.

Transmission conductor connections are treated with corrosion inhibitors to avoid connection oxidation. Connections are assembled using aluminum bolts, nuts, and lock washers. The connections are torqued to flatten the lock washer when installed to avoid loss of pre-load.

Based on design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for transmission conductor connections at Surry.

[3.6.1-006] - Loss of material due to wind induced abrasion and increased electrical resistance of connection due to oxidation or loss of pre-load are not applicable for aluminum and stainless steel components exposed to outdoor air environments in the switchyard bus and connections component group for SPS.

SPS uses aluminum tubular switchyard bus supported by station post insulators mounted on steel structures in concrete foundations. Connections between switchyard bus and active components such as circuit breakers are by short lengths of flexible aluminum 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.

SPS is located in a largely agricultural area on the James River, a fresh to brackish water supply. Salt spray and salt coating has not been experienced on switchyard components at SPS. There are no nearby industrial facilities that produce airborne industrial effluents affecting SPS. Aluminum cable and bus material does not experience any appreciable aging effects in this environment.

Buses 5, 6, and 7 in the Surry 34.5 kV switchyard were completely rebuilt in the 2005 to 2010 time period. The electrical bus, disconnect switches, circuit breakers, connecting bare cable, and terminations were replaced with new equipment. Also, the underground insulated cables that connect from the 34.5 kV circuit breakers to overhead cable for the A and B RSSTs, and that connect to tubular (switchyard) bus for the C RSST were replaced in the same time period. An additional section of the overhead 34.5 kV line for the A RSST was replaced with underground cable in 2014.

Aluminum switchyard bus and cable connections are treated with corrosion inhibitors to avoid connection oxidation. Connection hardware includes aluminum and stainless steel. Connections that are assembled using aluminum bolts and nuts do not use lock washers, but are torqued to prevent loss of preload. Connections that are assembled using stainless steel bolts and nuts include lock washers and are torqued to prevent loss of preload.

Based on design and confirmed by 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 at Surry.

[3.6.1-007] - Loss of material due to wind-induced abrasion is not applicable for aluminum transmission conductors exposed to outdoor air environments in the Transmission Conductors component group for SPS.

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 at SPS in-scope of subsequent license renewal operate at distribution voltages (34.5 kV) instead of transmission voltages. They are installed with shorter spans, at lower elevations, and with less sag than transmission conductors. Thus, they tend to be less affected by wind loading than transmission conductors.

Based on design and confirmed by operating experience, wind-induced abrasion is not an applicable aging mechanism for transmission conductors at Surry.

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 B.

3.6.2.2.5 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B.

3.6.2.3 Aging Management Review Results Not Consistent With or Not Addressed in the Generic Aging Lessons Learned for Subsequent License Renewal Report

Fuse Holders – Not Part of Active Equipment (Metallic Clamps and Insulation Material)

The individual fuse holders not part of active equipment subject to aging management review were identified from a review of electrical drawings. The results of this review identified five fuse holders at SPS that require aging management review. Each of these five fuse holders is mounted in an enclosed box located in the air – indoor controlled environment of either the control room, the emergency switchgear room, or the instrument rack room. The evaluation of aging effects is discussed below.

<u>Chemical Contamination, Corrosion, and Oxidation (Metallic Clamps)</u>

Each of the five subject fuse holders at SPS is located in either the control room, the emergency switchgear room, or the instrument rack room in a controlled environment that does not subject them to environmental aging mechanisms. The environment inside the room is air-conditioned by a ventilation system, thus the fuse holders do not experience high relative humidity during normal conditions. There are no sources of chemicals in the vicinity of the fuse holder enclosures during normal conditions.

A walkdown of the electrical enclosures containing the subject fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. Therefore, chemical contamination, corrosion, and oxidation are not considered applicable aging mechanisms for these fuse holders.

<u>Ohmic Heating, Thermal Cycling, and Electrical Transients (Metallic Clamps)</u>

Fuse holders for circuits that carry significant current in power applications could potentially be exposed to thermal fatigue in the form of high resistance caused by thermal cycling and ohmic heating. Instrumentation and control power circuits characteristically operate at low currents where no appreciable thermal cycling or ohmic heating occurs.

The subject fuse holders at SPS are for communications handsets, remote monitoring panel instrumentation, and a containment high range radiation monitor. These loads are instrumentation and control circuits that operate at low power where no appreciable thermal cycling or ohmic heating occurs. Therefore, electrical and thermal cycling is not considered an applicable aging mechanism for these fuse holders.

Mechanical stress due to forces associated with electrical faults and transients is mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature.

Frequent Manipulation and Vibration (Metallic Clamps)

Wear and fatigue is caused by repeated insertion and removal of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e., removal and reinsertion) because they are neither tagging nor isolation points which support periodic testing or preventive maintenance. Additionally, if fuses are manipulated for non-routine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse clips.

These subject fuse holders are located in enclosures that are not mounted on rotating or reciprocating equipment such as compressors, fans, or pumps. Because the enclosures are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the metallic clamps of these fuse holders will not exhibit the aging effects/mechanisms of fatigue due to frequent manipulation or vibration.

Reduced Electrical Insulation Resistance (Insulation Material)

The subject fuse holders are mounted inside enclosed boxes in either the control room, the emergency switchgear room, or the instrument rack room. These areas are air conditioned by permanent ventilation units maintaining the fuse holders in a controlled temperature, low humidity environment during normal conditions. The fuse holders are not subject to outside weather conditions and are further protected from incidental exposure to moisture by being mounted inside an enclosure. The control room, emergency switchgear room, and instrument rack room are mild environments and do not experience elevated levels of radiation. The fuse holders are not exposed to solar radiation and are protected from exposure to light fixtures by their enclosures. Therefore, the insulation material of these fuse holders will not exhibit the aging effects of reduced electrical insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis, and photolysis of organics, radiation-induced oxidation, and moisture intrusion.

Conclusion

Based on installed location, design configuration, operating service conditions, and operating experience, the five subject fuse holders inside the enclosures located in SPS control room, emergency switchgear room, and instrument rack room are not susceptible to the aging effects and mechanisms associated with metallic clamps and insulation material. Therefore, aging management activities are not required for these five Fuse Holders – Not Part of Active Equipment (Metallic Clamps) and Fuse Holders – Not Part of Active Equipment (Insulation Materials) at SPS.

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)	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 exposed to air – outdoor	Loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	AMP XI.E7, High-Voltage Insulators	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for High-Voltage Insulators (B2.1.44) program implementation.
3.6.1-003	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination	AMP XI.E7, High-Voltage Insulators	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for High-Voltage Insulators (B2.1.44) program implementation.

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
3.6.1-004	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)	Not applicable. SPS has no in-scope transmission conductors composed of aluminum and steel exposed to an air – outdoor environment. The associated NUREG-2191 aging items are not used. 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 transmission connectors exposed to an air-outdoor environment is not applicable to SPS. 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 and stainless steel exposed to an air-outdoor environment is not applicable to SPS. See further evaluation in Section 3.6.2.2.3.
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 to SPS. 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.

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
3.6.1-009	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.
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 (B2.1.40) program, the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.41) program or the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.39) 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
3.6.1-011	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	Consistent with NUREG-2191 with exceptions. Surface cracking, crazing, scuffing, dimensional change (e.g. “ballooning” and “necking”), shrinkage, discoloration, hardening or loss of strength of metal enclosed bus enclosure assemblies composed of elastomers exposed to an air – indoor controlled or air-indoor uncontrolled environment is managed by the Metal Enclosed Bus (B2.1.42) program. Exceptions apply to the NUREG-2191 recommendations for Metal Enclosed Bus (B2.1.42) program implementation
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Metal Enclosed Bus (B2.1.42) program implementation
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Metal Enclosed Bus (B2.1.42) program implementation

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
3.6.1-014	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	Consistent with NUREG-2191 with exceptions. Loss of material due to general, pitting, or crevice corrosion of metal enclosed bus enclosure assemblies composed of steel exposed to an air-indoor uncontrolled environment is managed by the Metal Enclosed Bus (B2.1.42) program. Exceptions apply to the NUREG-2191 recommendations for Metal Enclosed Bus (B2.1.42) program implementation.
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. SPS has no in-scope metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor in the Electrical and Instrumentation and Controls commodity groups. The associated NUREG-2191 aging items are not used.
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	Not applicable. SPS has no in-scope fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor uncontrolled in the Electrical and Instrumentation and Controls commodity groups. 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
3.6.1-017	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	Not applicable. Fuse holders within the scope of subsequent license renewal that are not part of active equipment are not subject to increased electrical resistance of connection due to fatigue from ohmic heating, thermal cycling, or electrical transients as described in Section 3.6.2.3.
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	Not applicable. Fuse holders within the scope of subsequent license renewal that are not part of active equipment are not subject to fatigue caused by frequent fuse removal/manipulation or vibration as described in Section 3.6.2.3.
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.

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
3.6.1-021	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	Consistent with NUREG-2191.
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	Not applicable. Fuse holders within the scope of subsequent license renewal that are not part of active equipment are located in an environment that does not subject them to environmental aging mechanisms as described in Section 3.6.2.3.
3.6.1-023	Metal enclosed bus: external surface of enclosure assemblies. Galvanized steel; aluminum air – indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191.
3.6.1-024	Metal enclosed bus: external surface of enclosure assemblies. Steel air – indoor controlled	None	None	No	Consistent with NUREG-2191.
3.6.1-027	Cable bus: external surface of enclosure assemblies galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Not applicable. SPS has no in-scope cable 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
3.6.1-029	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)	Not applicable. SPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.
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. SPS has no in-scope cable bus. 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)	Not applicable. SPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.
3.6.1-032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not applicable. SPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.

Intentionally Blank

Results Tables: Electrical and Instrumentation and Controls AMR Results

Table 3.6.2-1 Electrical and Instrumentation and Controls - Cables and Connections - Aging Management Evaluation

Component Type	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 (B2.1.43)	VI.A.LP-30	3.6.1-019	A
			(E) Air – indoor uncontrolled	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.43)	VI.A.LP-30	3.6.1-019	A
			(E) Air – outdoor	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.43)	VI.A.LP-30	3.6.1-019	A
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	None	None	VI.A.LP-24	3.6.1-022	I, 5
Fuse Holder - Not Part of Active Equipment (Metallic Clamps)	CE	Various metals used for electrical connections	(E) Air – indoor controlled	None	None	VI.A.L-07	3.6.1-017	I, 6
						VI.A.LP-31	3.6.1-018	I, 6

Table 3.6.2-1 Electrical and Instrumentation and Controls - Cables and Connections - 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 Material for Electrical Cable and Connections Used in Instrumentation Circuits	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 Used in Instrumentation Circuits (B2.1.38)	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 (B2.1.37)	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	(E) 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 (B2.1.40)	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	(E) 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 (B2.1.41)	VI.A.LP-35c	3.6.1-010	A

Table 3.6.2-1 Electrical and Instrumentation and Controls - Cables and Connections - 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 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	(E) 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 (B2.1.39)	VI.A.LP-35a	3.6.1-010	A
Switchyard Bus and Connections	CE	Aluminum	(E) Air – outdoor	None	None	VI.A.LP-39	3.6.1-006	I, 1
		Stainless steel	(E) Air – outdoor	None	None	VI.A.LP-39	3.6.1-006	I, 1
Transmission Conductors	CE	Aluminum	(E) Air – outdoor	None	None	VI.A.LP-47	3.6.1-007	I, 2
						VI.A.LP-46	3.6.1-021	I, 4
Transmission Connections	CE	Aluminum	(E) Air – outdoor	None	None	VI.A.LP-48	3.6.1-005	I, 3

Table 3.6.2-1 Plant-Specific Notes:

1. Loss of material and increased resistance of connection are not applicable aging effects for switchyard bus and connections at SPS. 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 at SPS. The in-scope transmission conductors are not subject to wind induced abrasion.

3. Increased resistance of connection is not an applicable aging effect for transmission connections at SPS. 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 at SPS. The in-scope transmission conductors are all-aluminum conductor construction and have the same characteristics as aluminum conductor aluminum alloy reinforced transmission conductors.

5. Reduced electrical insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis, and photolysis of organics, radiation-induced oxidation, and moisture intrusion are not aging effects for electrical insulation associated with fuse holders that are not part of active equipment at SPS. The fuse holders are contained within enclosed boxes and located in an air - indoor controlled environment. The fuse holders are not subject to outside weather conditions and are further protected from incidental exposure to moisture by being mounted inside an enclosure. These enclosures are within mild environments that do not experience elevated levels of radiation. The fuse holders are not exposed to solar radiation and are protected from exposure to light fixtures by their enclosures.

6. Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/manipulation or vibration, or due to fatigue due to ohmic heating, thermal cycling, or electrical transients is not an aging effect for fuse holders not part of active equipment at SPS. Fuse holders not part of active equipment are located in an air - indoor controlled environment and supply low power, instrumentation and communication circuits that are constantly energized. These circuits operate at low power where no appreciable thermal cycling or ohmic heating occurs. There are no sources of chemicals in the vicinity of the fuse holder enclosures during normal conditions. Fuse holders are not mounted near rotating or reciprocating equipment and are not subject to vibration. Upstream circuit breakers are used for tagging/isolation so that the fuse holders are not subject to frequent manipulation.

Table 3.6.2-2 Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
High voltage insulators	IN	Aluminum	(E) Air – outdoor	Loss of material	High-Voltage Insulators (B2.1.44)	VI.A.LP-32	3.6.1-002	B
		Cement	(E) Air – outdoor	Loss of material	High-Voltage Insulators (B2.1.44)	VI.A.LP-32	3.6.1-002	B
		Galvanized steel	(E) Air – outdoor	Loss of material	High-Voltage Insulators (B2.1.44)	VI.A.LP-32	3.6.1-002	B
		Malleable iron	(E) Air – outdoor	Loss of material	High-Voltage Insulators (B2.1.44)	VI.A.LP-32	3.6.1-002	B
		Porcelain	(E) Air – outdoor	Loss of material	High-Voltage Insulators (B2.1.44)	VI.A.LP-32	3.6.1-002	B
				Reduced electrical insulation resistance	High-Voltage Insulators (B2.1.44)	VI.A.LP-28	3.6.1-003	B

Table 3.6.2-2 Plant-Specific Notes: None

Table 3.6.2-3 Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bus and connection insulation	IN	Porcelain	(E) Air – indoor controlled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	B
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	B
		Thermo-plastic organic polymers	(E) Air – indoor controlled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	B
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	B
		Xenoy	(E) Air – indoor controlled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	B
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	B
Bus and connections	CE	Various metals used for electrical bus and connections	(E) Air – indoor controlled	Increased electrical resistance of connection	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-25	3.6.1-012	B
			(E) Air – indoor uncontrolled	Increased electrical resistance of connection	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-25	3.6.1-012	B

Table 3.6.2-3 Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bus enclosure	EN	Aluminum	(E) Air – indoor uncontrolled	None	None	VI.A.LP-41	3.6.1-023	A
		Elastomer	(E) Air – indoor controlled	Surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, hardening, loss of strength	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-29	3.6.1-011	B
			(E) Air – indoor uncontrolled	Surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, hardening, loss of strength	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-29	3.6.1-011	B
		Steel	(E) Air – indoor controlled	None	None	VI.A.LP-44	3.6.1-024	A
			(E) Air – indoor uncontrolled	Loss of material	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-43	3.6.1-014	B

Table 3.6.2-3 Plant-Specific Notes: None

Table 3.6.2-4 Electrical and Instrumentation and Controls - Electrical Equipment Subject to 10 CFR 50.49 Environmental Qualification - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Electrical Equipment Subject to 10 CFR 50.49 Environmental Qualification	CE	Various metallic materials	(E) Areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment. Adverse localized environment (e.g., temperature, radiation, or moisture)	Various aging effects (for EQ)	Environmental Qualification of Electric Equipment (B3.3)	VI.B.L-05	3.6.1-001	A
Electrical Equipment Subject to 10 CFR 50.49 Environmental Qualification	IN	Various polymeric materials	(E) Areas of the plant that could be subject to harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment. Adverse localized environment (e.g., temperature, radiation, or moisture)	Various aging effects (for EQ)	Environmental Qualification of Electric Equipment (B3.3)	VI.B.L-05	3.6.1-001	A

Table 3.6.2-4 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.

Intentionally Blank

4.0 TIME-LIMITED AGING ANALYSES

4.1 INTRODUCTION

Time-Limited Aging Analyses (TLAAs) are described in 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 Surry Power Station (SPS). 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* program (Section 4.2)
- *Metal Fatigue* program (Section 4.3)
- *Environmental Qualification of Electric Equipment* program (Section 4.4)
- *Concrete Containment Tendon Prestress* program (Section 4.5)
- *Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis* program (Section 4.6)
- *Other Plant-Specific Time-Limited Aging Analyses* program (Section 4.7)
- *References for Section 4 TLAAs* program (Section 4.8)

4.1.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

An analysis, calculation, or evaluation is a TLAA under the 10 CFR 54 License Renewal Rule, only if it meets all six of the following 10 CFR 54.3(a) criteria:

1. Involves systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);
2. Considers the effects of aging;
3. Involves time-limited assumptions defined by the current operating term, for example, 40 years;
4. Was determined to be relevant by the licensee in making a safety determination;
5. Involves 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. Is contained or incorporated by reference in the current licensing basis (CLB).

TLAAs from the initial license renewal were reviewed against the definition in 10 CFR 54.3(a) to determine whether TLAAs meet the definition of TLAA for the subsequent period of extended operation. In addition, other potential TLAAs were identified and reviewed against the definition of TLAAs in 10 CFR 54.3(a).

In accordance with 10 CFR 54.21(c)(1), a license renewal application must include a list of TLAAs, as defined in 10 CFR 54.3. The applicant shall demonstrate that -

- (i) The analyses remain valid for the period of extended operation;
- (ii) The analyses have been projected to the end of the period of extended operation; or
- (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

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 1.7-4)
- NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants” (Reference 1.7-3)
- NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal” (Reference 1.7-6)
- 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”
- 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:

- Updated Final Safety Analysis Report (UFSAR) (Reference 1.7-18)
- Technical Specifications and Bases (Reference 1.7-17)
- NRC Safety Evaluation Reports (SERs) for the original operating license
- Subsequent NRC Safety Evaluations (SEs)
- Docketed licensing correspondence between Virginia Electric and Power Company and 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. For each TLAA from the initial license renewal there is a corresponding TLAA 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.

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 period of extended operation;
   - (ii) The analyses have been projected to the end of the period of extended operation; or
   - (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

One of these three methods was 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) requires a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

Docketed correspondence, the operating license, and the UFSAR 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 exemptions to 10 CFR 50.12 identified that are currently in effect that are based upon a TLAA.

4.1.5 SUMMARY OF RESULTS

Table 4.1.5-1, Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1, lists the example TLAAs provided in NUREG-2192 and specifies whether they have been identified as TLAAs. The section(s) where the TLAA(s) are evaluated are identified. Those examples with a “Yes” entry apply. Those examples with a “No” entry do not apply and 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 of this chapter describe the evaluations of six general categories of TLAAs. The TLAA categories and associated analysis are listed in Table 4.1.5-2, Time-Limited Aging Analyses Categories and Dispositions. The TLAA categories are presented 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 in evaluating the TLAA and include a reference to the applicable subsequent license renewal application (SLRA) section where the TLAA is evaluated 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 SPS	SLRA Section
Neutron Fluence	Yes	Section 4.2.1
Pressurized Thermal Shock (PWRs Only)	Yes	Section 4.2.3
Upper Shelf Energy (PWRs and BWRs)	Yes	Section 4.2.2
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	No[a]	N/A
Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes	Section 4.3.4
Cycle-dependent Fatigue Waivers	Yes	Section 4.3.2.8
Environmental Qualification of Electric Equipment	Yes	Section 4.4
Concrete Containment Tendon Prestress	No	Section 4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	Section 4.6
Reactor Pressure Vessel Underclad Cracking	Yes	Section 4.7.7
Leak-Before-Break	Yes	Section 4.7.3
Reactor Coolant Pump Flywheel Fatigue Crack Growth	Yes	Section 4.7.2

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 SPS	SLRA Section
Response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification”	Yes	Section 4.3.2.6
Response to NRC Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Cooling Systems”	No[(a)]	N/A
Fatigue of Cranes (Crane Cycle Limits)	Yes	Section 4.7.1
Fatigue of the Spent Fuel Pool Liner	Yes	Section 4.7.4
Corrosion Allowance Calculations	No	N/A
Flaw Growth Due to Stress Corrosion Cracking	No	N/A
Predicted Lower Limit	No	N/A

Notes:

(a) No ASME Code, Section III cumulative usage factor (CUF) analyses were generated in response to NRC IE Bulletin 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	(ii)	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 Subsections	Section 4.3.2
	Control Rod Drive Mechanism	(iii)	Section 4.3.2.1
	Pressurizer	(iii)	Section 4.3.2.2
	Reactor Coolant Pump	(iii)	Section 4.3.2.3
	Reactor Vessel	(iii)	Section 4.3.2.4
	Steam Generators	(iii)	Section 4.3.2.5
	Pressurizer Surge Line	(iii)	Section 4.3.2.6
	Charging and Accumulator Piping	(iii)	Section 4.3.2.7
	ASME Code, Section III, Class I Component Fatigue Waivers	(iii)	Section 4.3.2.8
	ANSI B31.1 Allowable Stress Analyses	(i)	Section 4.3.3
	Environmentally-Assisted Fatigue	(iii)	Section 4.3.4
	Reactor Vessel Internals Fatigue Analyses	(i)	Section 4.3.5
ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT		(iii)	Section 4.4

Table 4.1.5-2 Time-Limited Aging Analyses Categories and Dispositions

TLAA CATEGORY	ANALYSIS	DISPOSITION (Note 1)	SECTION
CONCRETE CONTAINMENT TENDON PRESTRESS	Concrete Containment Tendon Prestress	Not Applicable	Section 4.5
CONTAINMENT LINER PLATE, METAL CONTAINMENTS & PENETRATIONS FATIGUE ANALYSES	Containment Liner Plate	(ii)	Section 4.6.1
	Metal Containment	N/A	Section 4.6.2
	Containment Penetrations Fatigue Analyses	Not a TLAA	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
	Spent Fuel Pool Liner Fatigue Analyses	(ii)	Section 4.7.4
	Piping Subsurface Flaw Evaluations	(ii)	Section 4.7.5
	Reactor Coolant Pump Code Case N-481	(i)	Section 4.7.6
	Cracking Associated with Weld Deposited Cladding	(ii)	Section 4.7.7
	Steam Generator Tube High Cycle Fatigue Evaluation	(ii)	Section 4.7.8
	Steam Generator Tube Wear Evaluation	(iii)	Section 4.7.9

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, 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 earlier versions of ASTM E185, “Standard Practice for Design of Surveillance Programs for Light-Water Moderated Nuclear Power Reactor Vessels” (Reference 4.8-1) that existed at the time of initial plant construction. 10 CFR 50.61 requires that all light water reactors meet the fracture toughness requirements for protection against pressurized thermal shock 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 Units 1 and 2 RV materials are presented in Table 4.2.2-1 through Table 4.2.2-4. The best estimate weight percent Cu and Ni values for the RV materials were reported in PWROG-16045-NP, “Determination of Unirradiated RT_{NDT} and Upper-Shelf Energy Values of the Units 1 and 2 Reactor Vessel Materials” (Reference 4.8-2) 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-18028-NP, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 & 2" (Reference 4.8-3), WCAP-18242-NP, “Surry Units 1 and 2 Time Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal” (Reference 4.8-4) and PWROG-16045-NP. Revised initial material properties, including chemistry factors and fluence projections, through 68 EFPY are included in and Table 4.2.3-2 for Units 1 and 2 respectively.

The neutron fluence axial boundary of the 1.0 x 10^{17} n/cm^2 fluence threshold is depicted in Figures 4.2.2-1 and 4.2.2-2 for Units 1 and 2 respectively. The configuration of the RVs, including the weld identification (ID) numbers, is illustrated in Figures 4.2.2-3 and 4.2.2-4 for Units 1 and 2, respectively.

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 x10^{17} n/cm^2 during the subsequent period of extended operation.

The ferritic materials of the RV 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. Because these neutron embrittlement analyses use a fluence assumption based on the plant's current operating term, they are identified as time-limited aging analyses.

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 vessel 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 initial design and fabrication of the RVs for Units 1 and 2, which were a minimum Charpy impact energy value of 30 ft-lbs at 10°F as specified by ASTM E208, “Standard Test Method for Conducting Drop-Weight Test to Determine Nil-Ductility Transition Temperature of Ferritic Steels” (Reference 4.8-5) and required by ASME Code, Section III, “Rules for Construction of Nuclear Facility Components” (Reference 4.8-6).

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. Since the cumulative neutron fluence will increase during the subsequent period of extended operation, a review is needed to determine if additional components require evaluation for neutron embrittlement.

10 CFR 50.61 requirements for pressurized thermal shock events specify screening criteria of 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. The 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. While the decrease in USE for materials in the extended beltline approaches (but remains greater than) 50 ft-lbs, as a conservative measure, an equivalent margins analysis has been performed for the inlet and outlet nozzle welds.

The NRC has approved use of revised initial (unirradiated) RT_{NDT} values and associated uncertainties for Linde 80 weld material. The NRC approved Topical Report BAW-2308 (Revision 1-A) in the "Final Safety Evaluation for Topical Report BAW-2308, Revision 1, 'Initial RT_{NDT} of Linde 80 Weld Materials'" (Reference 4.8-7). Table 3 of the Topical Report contains the revised initial reference temperature (IRT_{To}) and initial margin (I) values for Linde 80 weld materials that are approved by the NRC for the purpose of RV material property determination.

P-T limit curves are generated to provide minimum temperature limits that must be satisfied during operations. The P-T limit curves are based upon the RT_{NDT} and ΔRT_{NDT} values computed for the licensed operating period along with appropriate margins.

The enabling temperature and LTOP setpoint are validated as they are impacted by fluence.

The RV material evaluations, calculated on the basis of neutron fluence, are part of the current licensing basis 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 Analyses (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. 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 and will be treated as a TLAA.

TLAA Evaluation:

Per NUREG-1766, “Safety Evaluation Report Related to the License Renewal of North Anna Power Station, Units 1 and 2, and Surry Power Station, Units 1 and 2" (Reference 4.8-8), RV beltline neutron fluence values applicable to the 60-year period of operation were calculated using the NRC approved VEP-NAF-3-A, “Virginia Power Reactor Vessel Fluence Methodology Topical Report” (Reference 4.8-9). The methodology described in that report was developed in accordance with Draft Regulatory Guide DG-1053, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence” (Reference 4.8-10).

EFPY Projections

EFPY values for Unit 1 and 2 as of January 5, 2017 are as follows:

Unit 1	33.78 EFPY
Unit 2	33.69 EFPY

The first step in updating fluence projections for 80 years is to estimate the power history based upon actual unit operating history and a conservative capacity factor estimate for future cycles. Units 1 and 2 are 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 for a unit is the sum of the accumulated EFPY and the projected future EFPY. EFPY at the end of 60 years of operation was calculated to be 48 EFPY, assuming a 95% capacity factor for cycles beyond Cycle 19 for Unit 1, and for cycles beyond Cycle 18 for Unit 2. An estimate of the EFPY at the end of 80 years of operation can be made conservatively assuming a 100% capacity factor for the 20-year subsequent period of extended operation. Using this conservative approach the projected 80-year EFPY for both Units 1 and 2 is 68 EFPY.

Fluence Projections

Reactor vessel integrity is assured by demonstrating that RV material fracture toughness will remain at levels that resist brittle fracture throughout the subsequent period of extended operation. The first step in the analysis of vessel embrittlement is calculation of the neutron fluence that causes increased embrittlement.

Fluence is projected for both beltline and extended beltline materials. The fluence methodology for beltline materials is approved by the NRC SER included in WCAP-14040-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves” (Reference 4.8-11). NUREG-2191, X.M2, indicates the use of Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” (Reference 4.8-12) adherent methods to estimate neutron fluence for RV regions significantly above and below the active fuel region of the core and RVI components may require additional justification. Figures 4.2.2-1 and 4.2.2-2 depict the axial boundary of the 1.0×10^{17} n/cm^2 fluence in the Z direction. The nozzle shell to intermediate shell circumferential weld is located close to the active fuel region and has historically been treated as beltline material. The lower extent of the nozzle shell forging, connected to the nozzle shell to intermediate shell circumferential weld, is also beltline material. Fluence projections for these two materials satisfy Regulatory Guide 1.190. The inlet and outlet nozzles are located above the active fuel region. Some of the inlet and outlet nozzles are projected to experience neutron fluence in excess of 1.0×10^{17} n/cm^2. These inlet and outlet nozzles are treated as extended beltline material for subsequent license renewal.

While the fluence projections for the inlet and outlet nozzles may have greater uncertainty than other beltline materials, these fluence projections are acceptable for performing RV integrity assessments for the subsequent license renewal period. The basis for this determination is consistent with LTR-SDA-18-049, “Evaluation of Conservatisms and Margins Associated with Surry Units 1 and 2 Reactor Vessel Integrity Extended Beltline Evaluations for Subsequent License Renewal” (Reference 4.8-13) and LTR-REA-18-75, “Surry Extended Beltline Region Reactor Pressure Vessel Materials Fast Neutron Fluence Sensitivity Study on Material Mixture Above and Below the Active Core” (Reference 4.8-14), and is summarized as follows:

- The fluence at the inlet and outlet nozzles is significantly less than the fluence for the beltline materials, and the highest PTS and ART values are associated with the beltline materials,
- The projected fluence for the postulated flaw for the inlet and outlet nozzles assessed for the P-T Limit curves is based upon the lowest axial extent of the clad/ base metal interface on the inside radial surface of the RV without attenuation,
- Studies to date have shown that the DORT model calculates fluence in the Z direction above the core more conservatively than three-dimensional models such as RAPTOR-M3G,
- The controlling materials for PTS and P-T Limit curves continue to be the beltline materials,
- The fluence projections used in the SLR application conservatively utilized a constant material mixture of 90% water and 10% steel above and below the core. A sensitivity study was performed to show that this assumption was conservative compared to an analysis based upon more representative plant specific material mixture data above and below the core,

- The minimum fluence margin between the beltline materials and inlet and outlet nozzles is 178% (or 2.78 times) and represents the allowable increase in uncertainty that can be tolerated, and
- The SPS-specific minimum fluence margin of 178% (or 2.78 times) represents the increase in fluence uncertainty that is available relative to the customary use of +/-20% margin used in Regulatory Guide 1.190 for fluence projection.

Updated neutron fluence evaluations were performed and documented in WCAP-18028-NP. The fluence methodology used in WCAP-18028-NP is based on nuclear cross-section data derived from Evaluated Nuclear Data File/B Version VI (ENDF/B-VI). Furthermore, the neutron transport evaluation methodologies follow the guidance of Regulatory Guide 1.190. The methods used to develop the calculated pressure vessel fluence are consistent with the NRC-approved methodology described in WCAP-14040-A and are documented in the UFSAR, Section 4.1.7.3, “Calculation of Integrated Fast Neutron (E Greater than 1.0 MeV) Flux at the Irradiation Samples.” The final safety evaluation report for WCAP-14040, Revision 3, dated February 27, 2004, states that the proposed fluence methodology adheres to the guidance of Regulatory Guide 1.190 and is therefore acceptable. Updated neutron fluence evaluations were used as an input to the RV integrity evaluations in support of initial license renewal.

Consistent with Sections 3.1 and 4.2 of NUREG-2192, materials exceeding a fast neutron fluence (E > 1.0 MeV) 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. Therefore, fast neutron fluence (E > 1.0 MeV) calculations were performed for the Units 1 and 2 RV circumferential welds (lower shell to lower vessel head, intermediate shell to lower shell, and nozzle shell to intermediate shell), inlet and outlet nozzle forging to vessel shell welds at the lowest extent, postulated 1/4T flaw location in the inlet and outlet nozzle, longitudinal welds (lower shell and intermediate shell), and plates (lower shell and intermediate shell), to determine if they will exceed a fast neutron fluence (E > 1.0 MeV) 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 fluence (E > 1.0 MeV) threshold are evaluated to determine the effect of neutron irradiation embrittlement during the subsequent period of extended operation.

Table 4.2.1-1 and Table 4.2.1-2 summarize the results of the fluence projections to 68 EFPY for the Units 1 and 2 materials.

Table 4.2.1-1 indicates that some inlet and outlet nozzles have fast neutron fluence (E > 1.0 MeV) greater than 1.0×10^{17} n/cm^2 at the nozzle forging to vessel shell weld and one inlet nozzle has fast neutron fluence (E > 1.0 MeV) greater than 1.0×10^{17} n/cm^2 at the postulated 1/4T nozzle flaw location at 68 EFPY for Unit 1. Table 4.2.1-2, indicates that some inlet and outlet nozzles have fast neutron fluence (E > 1.0 MeV) greater than 1.0×10^{17} n/cm^2 at the nozzle forging to vessel shell weld and one outlet and one inlet nozzle have fast neutron fluence (E > 1.0 MeV) greater than 1.0×10^{17} n/cm^2 at the 1/4T nozzle flaw location at 68 EFPY for Unit 2. Table 4.2.1-1 and Table 4.2.1-2 indicate that the lower shell to lower vessel head circumferential weld will remain below 1.0×10^{17} n/cm^2 through the subsequent period of extended operation for both Units 1 and 2.

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. The results are to be used as inputs in the RV neutron embrittlement TLAA evaluations in Sections 4.2.2 through 4.2.6.

Table 4.2.1-1 Unit 1 - Maximum Fast Neutron Fluence (E > 1.0 MeV) Experienced by the Pressure Vessel Materials in the Traditional Beltline and Extended Beltline Regions at 68 EFPY at the Clad/Base Metal Interface

Material	Fast Neutron Fluence (n/cm^2)	
	68 EFPY	Region Applicability
Postulated 1/4T Flaw in Outlet Nozzle		
Nozzle 1	3.45E+16	N/A
Nozzle 2	2.49E+16	N/A
Nozzle 3	9.62E+16	N/A
Postulated1/4T Flaw in Inlet Nozzle		
Nozzle 1	1.24E+17	Extended
Nozzle 2	3.22E+16	N/A
Nozzle 3	4.46E+16	N/A
Outlet Nozzle Forging to Vessel Shell Welds – Lowest Extent		
Nozzle 1	8.13E+16	N/A
Nozzle 2	5.86E+16	N/A
Nozzle 3	2.27E+17	Extended
Inlet Nozzle Forging to Vessel Shell Welds – Lowest Extent		
Nozzle 1	3.04E+17	Extended
Nozzle 2	7.84E+16	N/A
Nozzle 3	1.09E+17	Extended
Nozzle Shell	7.54E+18	Traditional
Nozzle Shell to Intermediate Shell Circumferential Weld	7.54E+18	Traditional
Intermediate Shell		
Plate 1	6.29E+19	Traditional
Plate 2	6.29E+19	Traditional
Intermediate Shell Longitudinal Welds		
Weld 1	1.25E+19	Traditional
Weld 2	1.25E+19	Traditional
Intermediate Shell to Lower Shell Circumferential Weld	6.31E+19	Traditional
Plate 2	6.35E+19	Traditional
Lower Shell		
Plate 1	6.35E+19	Traditional
Plate 2	6.35E+19	Traditional

Material	Fast Neutron Fluence (n/cm^2)	
	68 EFPY	Region Applicability
Lower Shell Longitudinal Welds		
Weld 1	1.26E+19	Traditional
Weld 2	1.26E+19	Traditional
Lower Shell to Lower Vessel Head Circumferential Weld	<1E+17	Other[(a)]

(a) Dominion used N/A for situations where it is possible during the life of the plant to reach 1.0 x 10^{17} n/cm^2. EMAs were generated for these situations. The Lower Shell to Lower Vessel Head Circumferential Weld will never be in that category and are identified with a Region Applicability of "Other". EMAs were performed for all N/As.

Table 4.2.1-2 Unit 2 - Maximum Fast Neutron Fluence (E > 1.0 MeV) Experienced by the Pressure Vessel Materials in the Traditional Beltline and Extended Beltline Regions at 68 EFPY at the Clad/Base Metal Interface

Material	Fast Neutron Fluence (n/cm^2)	
	68 EFPY	Region Applicability
Postulated 1/4T Flaw in Outlet Nozzle[(a)]		
Nozzle 1	3.38E+16	N/A
Nozzle 2	2.48E+16	N/A
Nozzle 3	1.07E+17	Extended
Postulated 1/4T Flaw in Inlet Nozzle[(a)]		
Nozzle 1	1.39E+17	Extended
Nozzle 2	3.21E+16	N/A
Nozzle 3	4.37E+16	N/A
Outlet Nozzle Forging to Vessel Shell Welds – Lowest Extent		
Nozzle 1	7.96E+16	N/A
Nozzle 2	5.85E+16	N/A
Nozzle 3	2.53E+17	Extended
Inlet Nozzle Forging to Vessel Shell Welds – Lowest Extent		
Nozzle 1	3.40E+17	Extended
Nozzle 2	7.84E+16	N/A
Nozzle 3	1.07E+17	Extended
Nozzle Shell	8.65E+18	Traditional
Nozzle Shell to Intermediate Shell Circumferential Weld	8.65E+18	Traditional
Intermediate Shell		
Plate 1	7.20E+19	Traditional
Plate 2	7.20E+19	Traditional
Intermediate Shell Longitudinal Welds		
Weld 1	1.29E+19	Traditional
Weld 2	1.29E+19	Traditional
Intermediate Shell to Lower Shell Circumferential Weld	7.22E+19	Traditional
Lower Shell		
Plate 1	7.26E+19	Traditional
Plate 2	7.26E+19	Traditional

Material	Fast Neutron Fluence (n/cm^2)	
	68 EFPY	Region Applicability
Lower Shell Longitudinal Welds		
Weld 1	1.30E+19	Traditional
Weld 2	1.30E+19	Traditional
Lower Shell to Lower Vessel Head Circumferential Weld	<1E+17	Other[(b)]

(a) Nozzle 1/4T flaw maximum fluence valves are taken at the surface of the nozzle.

(b) Dominion used N/A for situations where it is possible during the life of the plant to reach 1.0 x 10^{17} n/cm^2. EMAs were generated for these situations. The Lower Shell to Lower Vessel Head Circumferential Weld will never be in that category and are identified with a Region Applicability of “Other”. EMAs were performed for all N/As.

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-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 ASME Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” (Reference 4.8-15) Appendix G, “Fracture Toughness Criteria for Protection Against Failure.” For materials outside the beltline, a minimum value of 30 ft-lbs at 10°F was specified by ASTM E208, and required by ASME Code, Section III, at the time of the design and fabrication of the RVs for Units 1 and 2.

The current licensing basis Charpy USE calculations were prepared for the Units 1 and 2 RV beltline materials for 48 EFPY. Since the USE value is a function of 48 EFPY fluence, associated with the 60-year licensed operating period, these USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation:

Per Regulatory Guide 1.99,“Radiation Embrittlement of Reactor Vessel Materials,” (Reference 4.8-16) the Charpy USE should be assumed to decrease as a function of fluence according to Figure 2 of the Regulatory Guide, 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 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 68 EFPY is used to determine the reduction of the initial USE.

As documented in WCAP-18242-NP, the materials projected to exceed 1.0 x 10^{17} n/cm^2 (E > 1.0 MeV) at 68 EFPY are evaluated to determine their impact on USE during the proposed subsequent period of extended operation. The forgings and welds corresponding to some 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. However, for conservatism all of the inlet and outlet nozzle materials are considered part of the extended beltline in the USE evaluation. The Units 1 and 2 materials include three (3) inlet nozzles, three (3) outlet nozzles, three (3) inlet nozzle to upper-shell welds, and three (3) outlet nozzle to upper-shell welds per unit. (Note: nozzle-shell and upper-shell refer to the same component and are used interchangeably).

The identification of the RV plate and weld materials is shown in Figure 4.2.2-1 for Unit 1 and Figure 4.2.2-2 for Unit 2. 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-16045-NP and WCAP-18242-NP, Appendix E, and the fluence values were updated per WCAP-18028-NP and WCAP-18242-NP, Section 2. Additionally, initial USE values are supplied in Table 4.2.2-1 and Table 4.2.2-3.

The requirements on USE for beltline materials are included in 10 CFR 50, Appendix G, which requires utilities to submit an analysis at least three years prior to the time that the USE of any RV material is predicted to drop below 50 ft-lb. Dominion has conservatively elected to perform equivalent margins analyses (EMAs) for inlet and outlet nozzle welds with Charpy USE near 50 ft-lb at the end of the subsequent period of extended operation.

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 Regulatory Guide 1.99. For vessel 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 Regulatory Guide 1.99. 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 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 exists the Position 2.2 projected USE value should be used in preference to the Position 2.1 projected USE value. Such cases exist in Table 4.2.2-5 wherein SLR USE values in the Position 1.2 section that fall below 50 ft-lbs are not an issue because corresponding values in the Position 2.2 section are above 50 ft-lbs when considering credible surveillance data.

The 68 EFPY Position 1.2 USE values of the vessel materials can be predicted using the corresponding fluence projections (1/4T for beltline materials and surface for inlet/outlet nozzles), the copper content of the materials, and Figure 2 in Regulatory Guide 1.99.

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 surveillance data along with the corresponding fluence projection (1/4T for beltline materials and surface for inlet/outlet nozzles). The reduced plant surveillance data was obtained from Table 7-6 of BAW-2324, “Analysis of Capsule X Virginia Power Surry Unit No. 1, Reactor Vessel Material Surveillance Program” (Reference 4.8-17) for Unit 1. The reduced plant surveillance data was obtained from Table 5-12 of WCAP-16001, “Analysis of Capsule Y from Dominion Surry Unit 2 Reactor Vessel Radiation Surveillance Program” (Reference 4.8-18) for Unit 2. The surveillance data was plotted in Regulatory Guide 1.99, Figure 2 using the surveillance capsule fluence values documented in Table 2-1 of WCAP-18242-NP, for Unit 1 and Table 2-2 of WCAP-18242-NP, for Unit 2.

The projected USE values were calculated to determine if the values for Units 1 and 2 materials remain above the 50 ft-lb criterion at 68 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 4.2.2-5 and Table 4.2.2-6.

Conclusion

For Unit 1, the limiting USE value at 68 EFPY is 32 ft-lb (see Table 4.2.2-5); this value applies to the Intermediate to Lower Shell Circumferential Weld using Position 1.2. For Unit 2, the limiting USE value at 68 EFPY is 41 ft-lb (see Table 4.2.2-6); this value applies to the Upper to Intermediate Shell Circumferential Weld using Position 1.2.

The NRC has previously approved the use of the equivalent margins analysis (EMA) BAW-2494, “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Surry Power Station Units 1 and 2 for Extended Life through 48 Effective Full Power Years” (Reference 4.8-19) to qualify all of the materials currently projected to drop below 50 ft-lb USE at 68 EFPY. These materials are identified by the notes in Table 4.2.2-1, Table 4.2.2-3, Table 4.2.2-5, Table 4.2.2-6 herein and are summarized below. The EMAs for these materials are updated for the subsequent period of extended operation under ANP-3679NP, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80 Years,” (Reference 4.8-20) and ANP-3680NP, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80 Years” (Reference 4.8-21). The updated EMA is based upon the provisions outlined in ASME Code, Section XI, Appendix K. The selection of design transients for Levels C & D service loads are based on the guidance in Regulatory Guide 1.161, “Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb.” (Reference 4.8-22) and ASME Code, Section XI, Appendix K.

An EMA should be submitted three years before a material is projected to drop below 50 ft-lbs; however, no additional materials are projected to drop below 50 ft-lb USE during the subsequent period of extended operation.

The following Unit 1 and Unit 2 materials are addressed by EMAs for the subsequent period of extended operation:

<u>Unit 1:</u>

- Upper to Intermediate Shell Circumferential Weld, Heat # 25017 (J726)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 8T1554
- Intermediate to Lower Shell Circumferential Weld, Heat # 72445
- Lower Shell Longitudinal Weld L1, Heat # 8T1554
- Lower Shell Longitudinal Weld L2, Heat # 299L44
- Inlet Nozzle to Shell Welds, Heat # 299L44 and # 8T1762; (Projected USE > 50 ft-lbs at 68 EFPY)
- Outlet Nozzle to Shell Welds, Heat # 8T1762 and # 8T1554B; (Projected USE > 50 ft-lbs at 68 EFPY)

<u>Unit 2:</u>

- Upper to Intermediate Shell Circumferential Weld, Heat # 4275 (J737)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 72445
- Intermediate Shell Longitudinal Weld L4, Heat # 8T1762
- Intermediate to Lower Shell Circumferential Weld, Heat # 0227
- Lower Shell Longitudinal Weld L1 and L2, Heat # 8T1762
- Inlet Nozzle to Shell Welds, Heat # 8T1762; (Projected USE not projected > 50 ft-lbs at 68 EFPY)
- Outlet Nozzle to Shell Welds, Rotterdam Weld; (Projected USE > 50 ft-lbs at 68 EFPY)

An EMA has been completed for the Unit 1 and Unit 2 Inlet and Outlet Nozzle to Shell Welds even though these materials are not projected to drop below 50 ft-lbs through 68 EFPY using the methods herein. The inlet and outlet nozzle welds are the only materials included in ANP-3679NP and ANP-3680NP that were not previously addressed by EMA. The EMA is applicable to the

Units 1 and 2 nozzle to shell welds which exceed the fluence criterion of 1.0 x 10^{17} n/cm^2 before 68 EFPY. These materials include those listed below.

- Unit 1 Outlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 3 to Upper Shell Weld
- Unit 2 Outlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 3 to Upper Shell Weld

For Unit 1, the limiting USE value for materials not requiring an EMA at 68 EFPY is 54 ft-lb (see Table 4.2.2-5); this value corresponds to the Inlet Nozzle to Upper Shell Welds (Heat # 299L44) using Position 2.2. For Unit 2, the limiting USE value for materials not requiring an EMA at 68 EFPY is also 54 ft-lb (see Table 4.2.2-6); this value corresponds to the Outlet Nozzle to Upper Shell Welds (Rotterdam) using Position 1.2. Except for the materials listed above, all of the beltline and extended beltline materials in the Units 1 and 2 RVs are projected to remain above the USE screening criterion value of 50 ft-lb (per 10 CFR 50, Appendix G) through the subsequent period of extended operation (68 EFPY).

Equivalent Margins Analysis

The ASME Code, Section XI, acceptance criteria for Levels A through D Service Loadings for all Units 1 and 2 RV beltline and extended beltline Linde 80 welds are satisfied and are reported in Framatome Reports BAW-2192, Supplement 1 (Revision 0), "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels A & B Service Loads Topical Report," (Reference 4.8-23) and BAW-2178, Supplement 1 (Revision 0), "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels C & D Service Loads Topical Report," (Reference 4.8-24) submitted to the NRC in December 2017. The Surry Power Plant specific versions of the EMA are documented in following reports:

- ANP-3679P, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80-Years" (Reference 4.8-25)
- ANP-3679NP, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80-Years"
- ANP-3680P, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80-Years" (Reference 4.8-26)
- ANP-3680NP, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80-Years"

The plant-specific EMA reports contain the same information as in BAW-2192, Supplement 1 and BAW-2178, Supplement 1 except that the information for Oconee 1, 2, and 3 and Turkey Point 3 and 4 has been removed.

The 80-year clad/base metal fluence values reported in Table 3 -1 of BAW-2178, Supplement 1, and Table 3-1 of BAW-2192, Supplement 1 have been confirmed to bound the 68 EFPY fluence values reported in Table 4.2.1-1 and Table 4.2.1-2. The EMAs conservatively utilized 80-year fluence values shown in (e) of at least an order of magnitude higher than the 68 EFPY nozzle fluence reported in Table 4.2.1-1 and Table 4.2.1-2. In addition, the weld chemistry data reported in Table 3-1 of BAW-2178, Supplement 1, and Table 3-1 of BAW-2192, Supplement 1 is consistent with weld chemistry reported in Tables 4.2.2-1 through Table 4.2.2-4. The level C and D limiting design transients reported in Section 4.3.2 of BAW-2178P, Supplement 1, are applicable to Units 1 and 2 and are based on a review of the ASME Code, Section III, Reactor Vessel Design Specification transients and the UFSAR Chapter 14 events relative to transients that would result in the highest thermal stresses coupled with pressure stresses relative to the EMA analysis; this satisfies Regulatory Guide 1.161 with respect to Level C and D transient selection. The materials of construction, RV geometry, and range of explanatory variables for the J-R model (Section A.5 of BAW-2192, Supplement 1) reported in the topical reports are confirmed to be applicable to Linde 80 and Rotterdam beltline and extended beltline welds at Units 1 and 2.

As such, Units 1 and 2 are bounded by topical report submittals BAW-2178, Supplement 1, and BAW-2192, Supplement 1 relative to fluence, weld chemistry, geometry, materials of construction, design transients and the J-R model applicability. The results of the EMA for Units 1 and 2, as reported in BAW-2178 P/NP and BAW-2192 P/NP, are summarized below.

Levels A & B Service Loadings

Reactor Vessel Shell Welds (Beltline)

The limiting RV shell weld is Unit 1 axial weld SA-1526.

- With factors of safety of 1.15 on pressure and 1.0 on thermal loading, the applied J-integral (J1) is less than the J-integral of the material at a ductile flaw extension of 0.10 in. (J0.1). The ratio J0.1/J1 is greater than the required value of 1.0.
- With a factor of safety of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

Reactor Vessel Transition Welds and RV Nozzle Welds (Extended Beltline)

- The limiting weld for Units 1 and 2 considering RV transition welds (upper and lower) and the RV inlet and outlet nozzle-to-shell welds is the longitudinal weld SA-1585 near the base of the transition section.
- With factors of safety of 1.15 on pressure and 1.0 on thermal loading, the applied J-integral (J1) is less than the J-integral of the material at a ductile flaw extension of 0.10 in. (J0.1). The ratio J0.1/J1 is greater than the required value of 1.0.
- With a factor of safety of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

Levels C & D Service Loadings

Reactor Vessel Shell Welds (Beltline)

The limiting weld among the RV shell welds is Unit 1 longitudinal weld SA-1526. The limiting transient for Level C & D service Loads is the SSDC 1.3 steam line break.

- With a factor of safety of 1.0 on loading, the applied J-integral (J1) for the limiting RV shell weld (Unit 1, SA-1526) is less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch (J0.1) with a ratio J0.1/J1 that is greater than the required value of 1.0.
- With a factor of safety of 1.0 on loading, flaw extensions are ductile and stable for the limiting RV shell weld (SA-1526) since the slope of the applied J-integral curve is less than the slopes of both the lower bound and mean J-R curves at the points of intersection.
- For weld SA-1526 it was demonstrated that flaw growth is stable at much less than 75% of the vessel wall thickness. It has also been shown that the remaining ligament is sufficient to preclude tensile instability.

Reactor Vessel Transition Welds and RV Nozzle Welds (Extended Beltline)

The upper transition weld and RV inlet and outlet nozzle-to-shell welds were evaluated for Levels C and D Service Loadings. The limiting transient for Level C & D service loads is the SSDC 1.3 steam line break.

- With a factor of safety of 1.0 on loading, the applied J-integral (J1) for the RV nozzle-to-shell welds and upper transition weld are less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch (J0.1). All ratios are greater than 1.0.
- With a factor of safety of 1.0 on loading, flaw extensions are ductile and stable for the limiting RV outlet nozzle-to-shell weld (i.e., limiting location considering RV nozzle-to-shell welds and upper transition weld).
- For the RV outlet nozzle-to-shell weld it was demonstrated that flaw growth is stable at much less than 75% of the vessel wall thickness. Tensile instability was not explicitly calculated but because this section of the RV is thicker compared to the RV shell welds, it is considered to be bounded by the RV shell location.

B&WOG J-R Model

The original B&WOG J-R Model 4B reported in BAW-2192PA, Supplement 1, Appendix A, was used to obtain J material (i.e., J(0.1)) for the 80-year equivalent margins analyses reported in BAW-2192, Supplement 1, and BAW-2178, Supplement 1. Model 4B is based on fracture toughness data (1352 J delta-a data points) irradiated to a fluence ranging from 0.0 to 8.45×10^{18} n/cm^2, which is less than the peak 1/10T 80-year fluence projected for Units 1 and 2. To further substantiate the use of the B&WOG J-R model, the original J delta-a data used to generate the B&WOG J-R model 4B was used to independently benchmark the original B&WOG model using the R-project statistical tool. The benchmark is designated B&WOG J-R Model 5B. New J-R data (419 new J delta-a data points with fluence to 5.8×10^{19} n/cm^2) were then added to the original population of welds (total population of 1774 data points) and the fitting coefficients (assuming the same model form) were generated. The B&WOG model that includes the total population of J delta-a data (1774) is designated Model 6B. Model 6B is based on test data out to a fluence of 5.8×10^{19} n/cm^2, which is greater than the peak 1/4T fluence of 8.16×10^{18} n/cm^2 and 1/10T fluence of 1.083×10^{19} n/cm^2 for Units 1 and 2 limiting weld SA-1526.

Use of Model 6B for fluence values in excess of 5.8×10^{19} n/cm^2 is considered to be a model extrapolation and the uncertainty may increase (i.e., -2SE). Fluence estimates at T/4 and T/10 are well below 5.8×10^{19} n/cm^2 and the J-R Model is used well within the interpolation range (i.e., for weld SA-1526 fluence equals 8.16×10^{18} n/cm^2 at 1/4T and 1.083×10^{19} n/cm^2 at T/10). For Units 1 and 2, use of Model 6B (model extrapolation) increased the J(0.1)/J1 by approximately 6% for Level A and B, and 5% for Level C and D when compared to Model 4B, and, all margins remain above the acceptance criterion of 1.0. In addition, the combination of Level C and D acceptance criteria applied to Level D transients provides additional conservatism in the equivalent margins analyses. The B&WOG J-R models (including Models 4B and 6B) are discussed in BAW-2192, Supplement 1, Appendix A.

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.

Figure 4.2.2-1 Unit 1 - Axial Boundary of the 1.0E+17 n/cm² Fluence Threshold in the +Z Direction (at 54 and 72 EFPY)

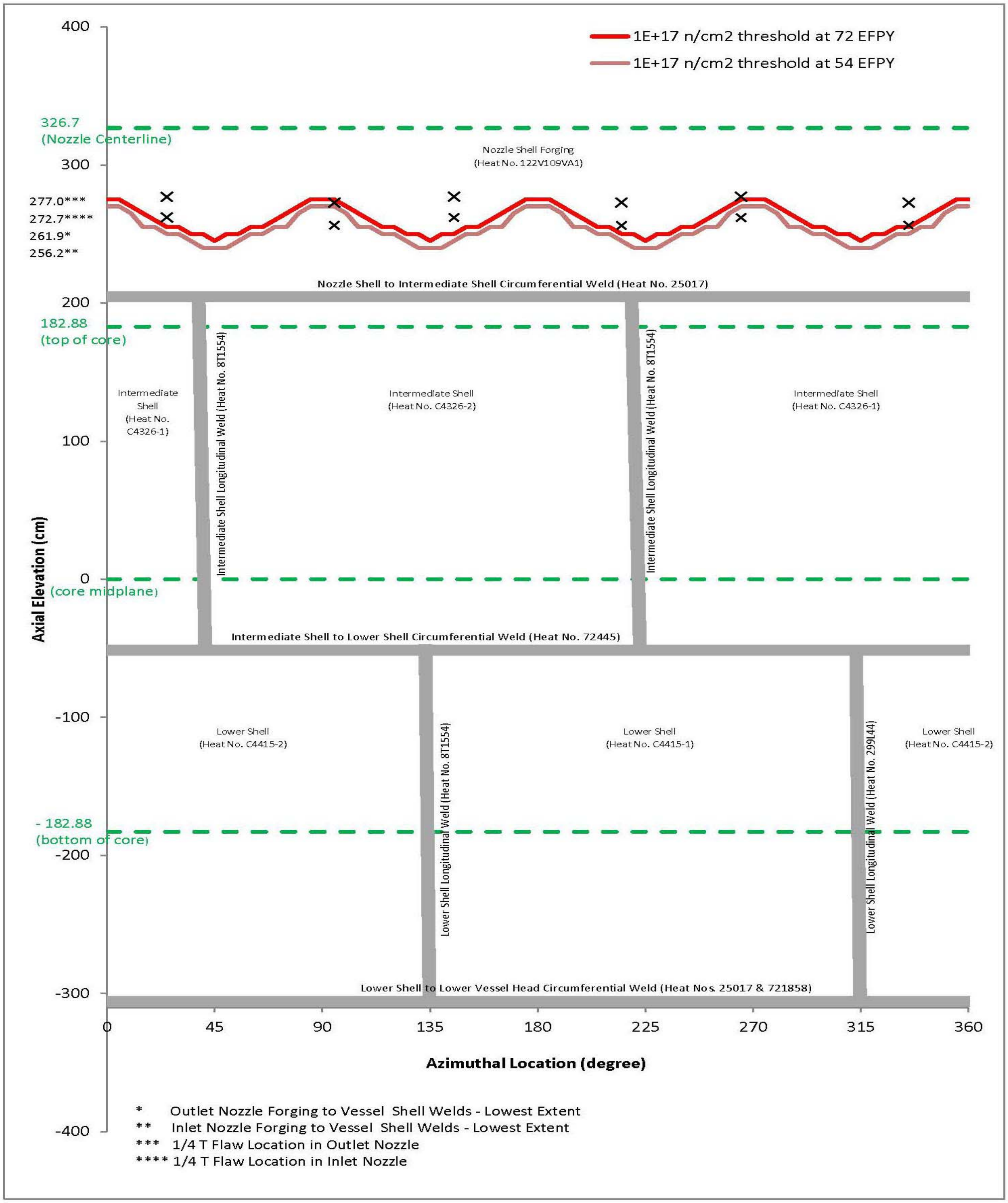


Figure 4.2.2-2 Unit 2 - Axial Boundary of the 1.0E+17 n/cm^2 Fluence Threshold in the +Z Direction (at 54 and 72 EFPY)

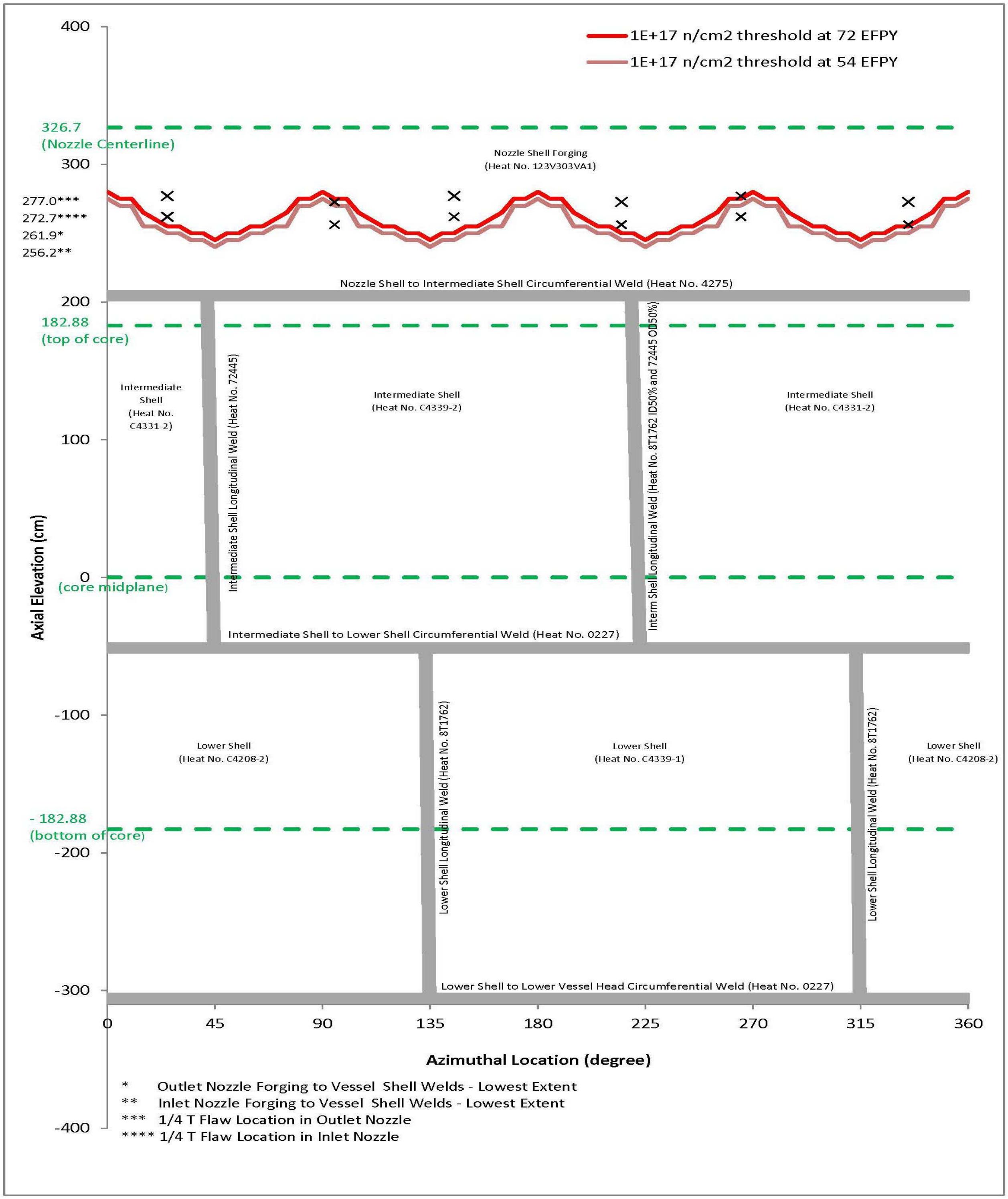
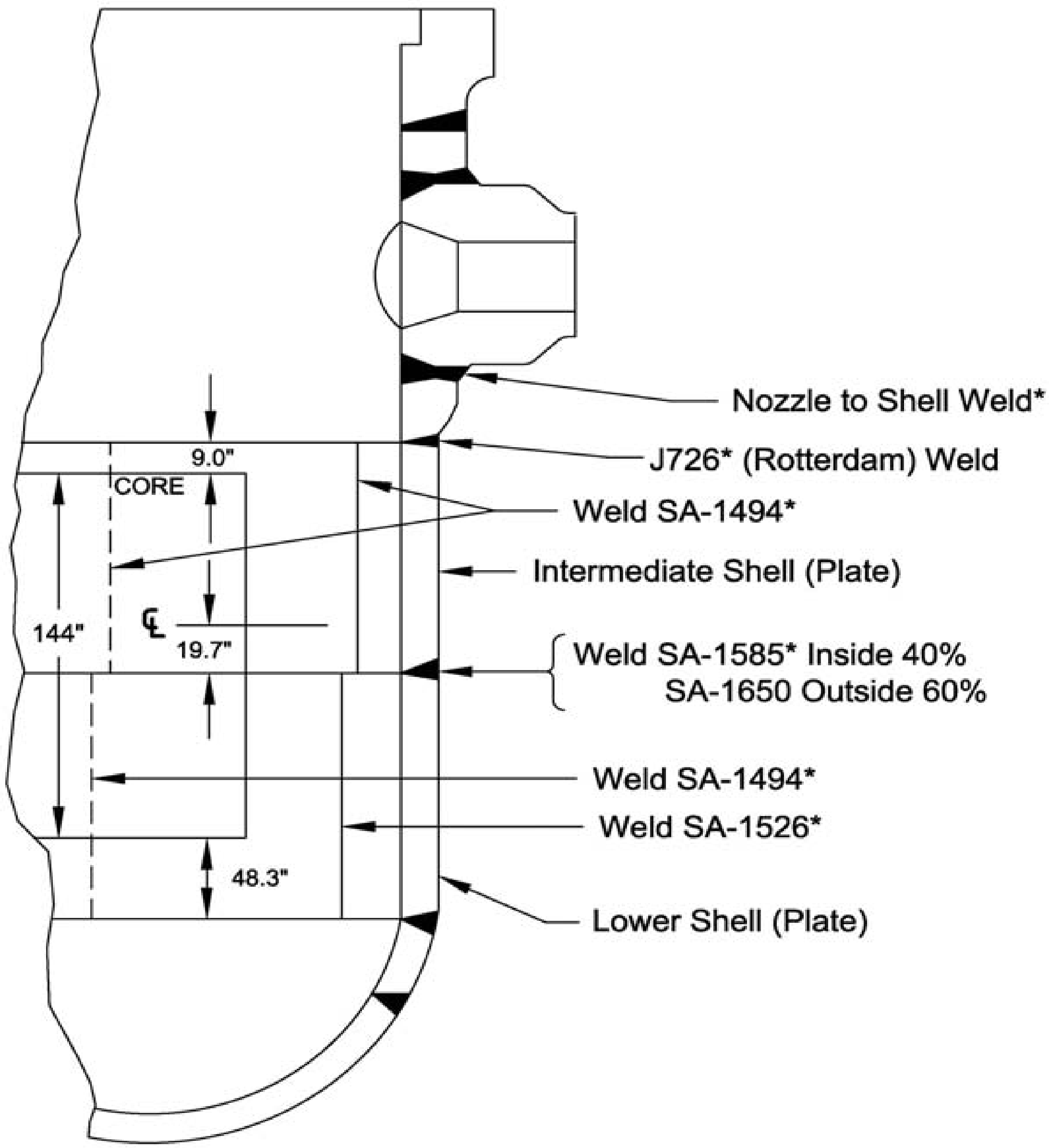
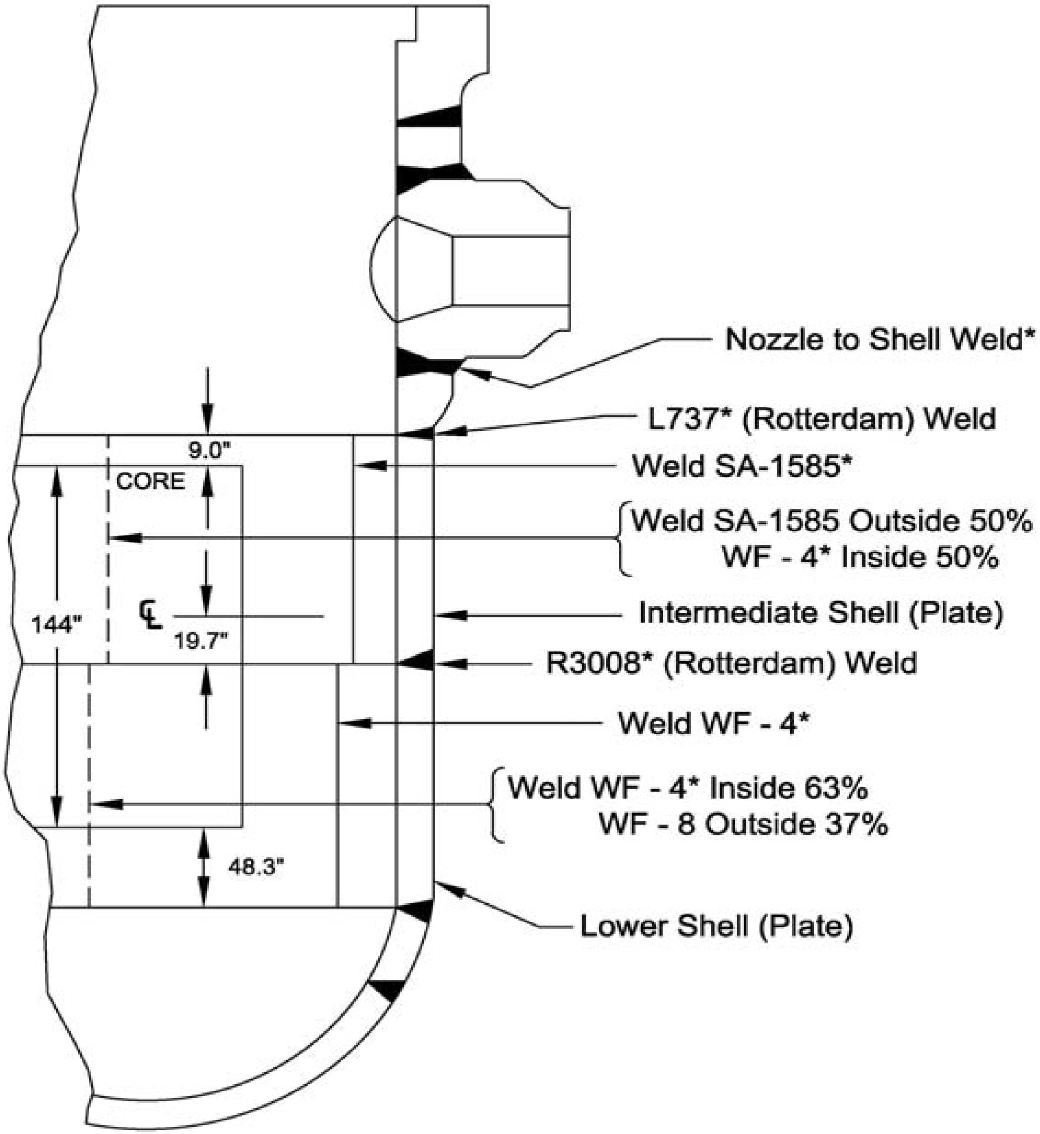


Figure 4.2.2-3 Reactor Vessel - Unit 1



* Equivalent Margins Analysis performed
for these Linde 80 and Rotterdam Welds.

Figure 4.2.2-4 Reactor Vessel - Unit 2



* Equivalent Margins Analysis performed for these Linde 80 and Rotterdam Welds.

Table 4.2.2-1 Best Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the Unit 1 RV Beltline and Surveillance Materials

RV Material	Wt.% Cu	Wt.% Ni	$RT_{NDT(U)}$ (°F)	σ_I (°F)	Initial USE (ft-lb)
RV Beltline Materials[a]					
Upper Shell Forging 122V109VA1	0.11	0.74	40	0	114
Intermediate Shell Plate C4326-1	0.11	0.55	10	0	115
Intermediate Shell Plate C4326-2	0.11	0.55	11.4	0	94
Lower Shell Plate C4415-1	0.102	0.493	20	0	103
Lower Shell Plate C4415-2	0.11	0.5	4.6	0	82
Upper to Intermediate Shell Circumferential Weld (Heat # 25017)	0.33	0.1	0	20	≥ 64[b]
Intermediate Shell Longitudinal Welds L3 and L4 (Heat # 8T1554)	0.16	0.57	-48.6	18	64[b]
Intermediate to Lower Shell Circumferential Weld (Heat # 72445)	0.22	0.54	-72.5	12	64[b]
Lower Shell Longitudinal Weld L1 (Heat # 8T1554)	0.16	0.57	-48.6	18	64[b]
Lower Shell Longitudinal Weld L2 (Heat # 299L44)	0.34	0.68	-74.3	12.8	64[b]
RV Surveillance Materials[c]					
Lower Shell Plate C4415-1	0.102	0.493	20	0	103
Surveillance Weld (Heat # 299L44)	0.23	0.64	- - -	- - -	70

Notes:

(a) All values were taken from Table 8 of PWROG-16045 NP, unless otherwise noted.

(b) Per UFSAR (Tables 4.1-14 and 4.1-15), RV Equivalent Margins Analysis (EMA) report BAW-2494, was approved for these welds for 48 EFPY. The EMAs are updated for the subsequent period of extended operation. Linde 80 initial USE values are set to the generic value of 64 ft-lbs per BAW-2313, Supplement 1. Only limited Charpy test information is available for Heat # 25017. Based on the average Charpy energy value of the weld qualification tests completed at 10°F, the USE for Heat # 25017 is at least 64 ft-lbs. This value of 64 ft-lbs is conservative compared to the generic Rotterdam weld results documented in PWROG-17090-NP, “Generic Rotterdam Forging and Weld Initial Upper-Shelf Energy Determination.” (Reference 4.8-27)

(c) The surveillance plate data was taken to be the same as the vessel plate data. The surveillance weld data was obtained from BAW-2324.

Table 4.2.2-2 Best Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the Unit 1 RV Materials

RV Material		Wt.% Cu	Wt.% Ni	$RT_{NDT(U)}$ (°F)	σ_I (°F)	Initial USE (ft-lb)
RV Extended Beltline Materials[a]						
Inlet Nozzle 1 (Heat # 9-4787)		0.159	0.85	10.3	0	63
Inlet Nozzle 2 (Heat # 9-5078)		0.159	0.87	11.6	0	64
Inlet Nozzle 3 (Heat # 9-4819)		0.159	0.84	-47.2	0	68
Outlet Nozzle 1 (Heat # 9-4825-1)		0.159	0.85	-44.9	0	68
Outlet Nozzle 2 (Heat # 9-4762)		0.159	0.83	-87.5	0	82
Outlet Nozzle 3 (Heat # 9-4788)		0.159	0.84	-50.2	0	71
Inlet Nozzle to Upper Shell Welds	Heat # 299L44	0.34	0.68	-7	20.6	64
	Heat # 8T1762	0.19	0.57	-4.9	19.7	64
Outlet Nozzle to Upper Shell Welds	Heat # 8T1762	0.19	0.57	-4.9	19.7	64
	Heat # 8T1554 B	0.16	0.57	-4.9	19.7	64

Note:

(a) All values were taken from Table 8 of PWROG-16045-NP.

Table 4.2.2-3 Best Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the Unit 2 RV Beltline and Surveillance Materials

RV Material	Wt.% Cu	Wt.% Ni	$RT_{NDT(U)}$ (°F)	σ_I (°F)	Initial USE (ft-lb)
RV Beltline Materials[a]					
Upper Shell Forging 123V303VA1	0.11	0.72	30	0	104
Intermediate Shell Plate C4331-2	0.12	0.6	15	0	84
Intermediate Shell Plate C4339-2	0.11	0.54	7.8	0	83
Lower Shell Plate C4208-2	0.15	0.55	-30	0	94
Lower Shell Plate C4339-1	0.107	0.53	-4.4	0	101
Upper to Intermediate Shell Circumferential Weld (Heat # 4275)	0.35	0.1	0	20	≥ 68[b]
Intermediate Shell Longitudinal Welds L3 and L4 (OD 50%) (Heat # 72445)	0.22	0.54	-72.5	12	64[b]
Intermediate Shell Longitudinal Weld L4 (ID 50%) (Heat # 8T1762)	0.19	0.57	-48.6	18	64[b]
Intermediate to Lower Shell Circumferential Weld (Heat # 0227)	0.187	0.545	0[c]	0[c]	82[c]
Lower Shell Longitudinal Welds L1 and L2 (Heat # 8T1762)	0.19	0.57	-48.6	18	64[b]
RV Surveillance Materials[d]					
Lower Shell Plate C4339-1	0.107	0.53	-4.4	0	101
Surveillance Weld (Heat # 0227)	0.19	0.56	- - -	- - -	91

Notes:

(a) All values were taken from Table 9 of PWROG-16045-NP, unless otherwise noted.

(b) Per UFSAR (Tables 4.1-14 and 4.1-15), RV EMA report BAW-2494 was approved for these welds for 48 EFPY. The EMAs are updated for the subsequent period of extended operation. Linde 80 initial USE values are set to the generic value of 64 ft-lbs per BAW-2313, Supplement 1, "Supplement to B&W Fabricated Reactor Vessel Materials and Surveillance Data Information for Surry Unit 1 and Unit 2" (Reference 4.8-28). Only limited Charpy test information is available for Heat # 4275. Based on the average Charpy energy value of the weld qualification tests completed at 10°F, the USE for Heat # 4275 is at least 68 ft-lbs. This value of 64 ft-lbs is conservative compared to the generic Rotterdam weld results documented in PWROG-17090-NP.

(c) Initial properties are established in Appendix B of WCAP-18242-NP. Since the initial RT_{NDT} is based on measured data, σ_u is equal to 0°F. Per UFSAR (Tables 4.1-14 and 4.1-15), RV EMA report BAW-2494 was approved for this weld for 48 EFPY. The EMA is updated for the subsequent period of extended operation.

(d) The surveillance plate data was taken to be the same as the vessel plate data. The surveillance weld data was obtained from WCAP-16001.

Table 4.2.2-4 Best Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the Unit 2 RV Extended Beltline Materials

RV Material		Wt.% Cu	Wt.% Ni	$RT_{NDT(U)}$ (°F)	σ_I (°F)	Initial USE (ft-lb)
RV Extended Beltline Materials[a]						
Inlet Nozzle 1 (Heat # 9-5104)		0.159	0.84	-29.7	0	73
Inlet Nozzle 2 (Heat # 9-4815)		0.159	0.87	4.5	0	66
Inlet Nozzle 3 (Heat # 9-5205)		0.159	0.86	6.5	0	67
Outlet Nozzle 1 (Heat # 9-4825-2)		0.159	0.85	-58.1	0	73
Outlet Nozzle 2 (Heat # 9-5086-1)		0.159	0.86	-26.6	0	77
Outlet Nozzle 3 (Heat # 9-5086-2)		0.159	0.87	-33.8	0	71
Inlet Nozzle to Upper Shell Welds	Heat # 8T1762	0.19	0.57	-4.9	19.7	64
Outlet Nozzle to Upper Shell Welds	Rotterdam	0.35	1	30	0	71[b]

Notes:

(a) All values were taken from Table 9 of PWROG-16045-NP. Associated σ, values are also available from PWROG-16045-NP.

(b) Per PWROG-16045-NP, this initial USE value is set equal to the USE value of the first tested capsule from WCAP-16001 (Reference 4.8-18). This methodology utilizes BTP 5-3 (Reference 4.8-29), Position 1.2 guidance, as no USE data is available from the supplier. The value used herein is conservative in comparison. In addition, Dominion conservatively elected to complete an EMA on this material.

Table 4.2.2-5 Predicted USE Values at 68 EFPY for Unit 1

RV Material	Wt.% Cu[a]	SLR 1/4T Fluence[b] (x 10^{19} n/cm^2)	Initial USE[a] (ft-lb)	Projected USE Decrease[c] (%)	SLR USE (ft-lb)
Position 1.2					
Upper Shell Forging 122V109VA1	0.11	0.465	114	17	95
Upper to Intermediate Shell Circumferential Weld[e] (Heat # 25017)	0.33	0.465	64	39	39[e]
Intermediate Shell Plate C4326-1	0.11	3.88	115	28	83
Intermediate Shell Plate C4326-2	0.11	3.88	94	28	68
Intermediate Shell Longitudinal Welds L3 and L4[e] (Heat # 8T1554)	0.16	0.771	64	29	45[e]
Intermediate to Lower Shell Circumferential Weld[e] (Heat # 72445)	0.22	3.89	64	50	32[e]
Lower Shell Plate C4415-1	0.102	3.92	103	27	75
Lower Shell Plate C4415-2	0.11	3.92	82	28.5	59
Lower Shell Longitudinal Weld L1[e] (Heat # 8T1554)	0.16	0.777	64	29	45[e]
Lower Shell Longitudinal Weld L2[e] (Heat # 299L44)	0.34	0.777	64	41	38[e]
Inlet Nozzle 1 to Upper Shell Weld (Heat # 299L44)	0.34	0.0188	64	24	49[f]
Inlet Nozzle 2 to Upper Shell Weld (Heat # 299L44)	0.34	0.00484	64	24	49[f]
Inlet Nozzle 3 to Upper Shell Weld (Heat # 299L44)	0.34	0.00672	64	24	49[f]
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	0.19	0.0188	64	13	56
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	0.19	0.00484	64	13	56
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	0.19	0.00672	64	13	56
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	0.19	0.00502	64	13	56
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	0.19	0.00362	64	13	56
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	0.19	0.0140	64	13	56
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1554B)	0.16	0.00502	64	12	56
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1554B)	0.16	0.00362	64	12	56

RV Material	Wt.% Cu[(a)]	SLR 1/4T Fluence[(b)] (x 10^{19} n/cm^2)	Initial USE[(a)] (ft-lb)	Projected USE Decrease[(c)] (%)	SLR USE (ft-lb)
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1554B)	0.16	0.0140	64	12	56
Inlet Nozzle 1 (Heat # 9-4787)	0.159	0.0304	63	11	56
Inlet Nozzle 2 (Heat # 9-5078)	0.159	0.0078	64	10	58
Inlet Nozzle 3 (Heat # 9-4819)	0.159	0.0109	68	10	61
Outlet Nozzle 1 (Heat # 9-4825-1)	0.159	0.0081	68	10	61
Outlet Nozzle 2 (Heat # 9-4762)	0.159	0.0059	82	10	74
Outlet Nozzle 3 (Heat # 9-4788)	0.159	0.0227	71	10.5	64
Position 2.2[(d)]					
Lower Shell Plate C4415-1	0.102	3.9200	103	28	74
Lower Shell Plate C4415-2	0.11	3.9200	82	28	59
Lower Shell Longitudinal Weld L2[(e)] (Heat # 299L44)	0.34	0.7770	64	35	42[(e)]
Inlet Nozzle 1 to Upper Shell Weld (Heat # 299L44)	0.34	0.0188	64	15	54
Inlet Nozzle 2 to Upper Shell Weld (Heat # 299L44)	0.34	0.0048	64	15	54
Inlet Nozzle 3 to Upper Shell Weld (Heat # 299L44)	0.34	0.0067	64	15	54

Notes:

(a) Material data is from Table 4.2.2-1 and Table 4.2.2-2.

(b) The 1/4T fluence was calculated using the fluence data in Table 4.2.1-1, the Regulatory Guide 1.99 correlation, and the Units 1 and 2 RV wall thickness of 8.05 inches. The surface fluence at the lowest extent of the nozzle weld was used to represent the inlet and outlet nozzle forgings; this approach is conservative. Bounding material fluence values, only, are shown in Figure 5-1 of WCAP-18242-NP for the nozzle materials.

(c) The Position 1.2 USE decrease values were calculated by plotting the 1/4T fluence values on Figure 2 of Regulatory Guide 1.99 and using the material specific Cu wt. percent values.

(d) Surveillance data (deemed credible per Appendix A of WCAP-18242-NP) from Table 7-6 of BAW-2324 were used in the calculation of Unit 1 Position 2.2 USE projections. Regulatory Guide 1.99, Position 2.2 indicates that an upper bound line drawn parallel to the existing lines (in Figure 2 of the Regulatory Guide) through the surveillance data points should be used in preference to the existing graph lines for determining the decrease in USE.

(e) These weld materials were previously addressed by EMA Report BAW-2494 for 48 EFPY. EMAs for these materials have been generated.

(f) Per Regulatory Guide 1.99 (Revision 2), when credible data exists the Position 2.2 projected USE value should be used in preference to the Position 2.1 projected USE value.

Table 4.2.2-6 Predicted USE Values at 68 EFPY for Unit 2

RV Material	Wt.% Cu[(a)]	SLR 1/4T Fluence[(b)] ($x10^{19}$ n/cm^2)	Initial USE[(a)] (ft-lb)	Projected USE Decrease[(c)] (%)	SLR USE (ft-lb)
Position 1.2					
Upper Shell Forging 123V303VA1	0.11	0.5340	104	18	85
Upper to Intermediate Shell Circumferential Weld[(e)] Heat # 4275	0.35	0.5340	68	39	41[(e)]
Intermediate Shell Plate C4331-2	0.12	4.4400	84	30	59
Intermediate Shell Plate C4339-2	0.11	4.4400	83	29	59
Intermediate Shell Longitudinal Welds L3 and L4 (OD 50%)[(e)] (Heat # 72445)	0.22	0.7960	64	34	42[(e)]
Intermediate Shell Longitudinal Weld L4 (ID 50%)[(e)] (Heat # 8T1762)	0.19	0.7960	64	32	44[(e)]
Intermediate to Lower Shell Circ. Weld[(e)] (Heat # 0227)	0.187	4.4500	82	47	43[(e)]
Lower Shell Plate C4208-2	0.15	4.4800	94	35	61
Lower Shell Plate C4339-1	0.107	4.4800	101	29	72
Lower Shell Longitudinal Weld L1 and L2[(e)] (Heat # 8T1762)	0.19	0.8020	64	33	43[(e)]
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	0.19	0.0210	64	14	55
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	0.19	0.0048	64	13.5	55
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	0.19	0.0066	64	13.5	55
Outlet Nozzle 1 to Upper Shell Weld (Rotterdam)	0.35	0.0049	71	24	54
Outlet Nozzle 2 to Upper Shell Weld (Rotterdam)	0.35	0.0036	71	24	54
Outlet Nozzle 3 to Upper Shell Weld (Rotterdam)	0.35	0.0156	71	24	54
Inlet Nozzle 1 (Heat # 9-5104)	0.159	0.0340	73	12.5	64
Inlet Nozzle 2 (Heat # 9-4815)	0.159	0.0078	66	10	59
Inlet Nozzle 3 (Heat # 9-5205)	0.159	0.0107	67	10	60
Outlet Nozzle 1 (Heat # 9-4825-2)	0.159	0.0080	73	10	66
Outlet Nozzle 2 (Heat # 9-5086-1)	0.159	0.0059	77	10	69
Outlet Nozzle 3 (Heat # 9-5086-2)	0.159	0.0253	71	10.5	64
Position 2.2[(d)]					
Lower Shell Plate C4339-1	0.107	4.4800	101	19	82
Intermediate Shell Plate C4339-2	0.11	4.4400	83	19	67
Intermediate to Lower Shell Circ. Weld[(e)] (Heat # 0227)	0.187	4.4500	82	42	48[(e)]

Notes:

(a) Material data is from Table 4.2.2-3 and Table 4.2.2-4.

(b) The 1/4T fluence was calculated using the fluence data in Table 4.2.1-2, the Regulatory Guide 1.99 correlation, and the Units 1 and 2 RV wall thickness of 8.05 inches. The surface fluence at the lowest extent of the nozzle weld was used to represent the inlet and outlet nozzle forgings; this approach is conservative. Bounding material fluence values, only, are shown in Figure 5-2 of WCAP-18242-NP for the nozzle materials.

(c) The Position 1.2 USE decrease values were calculated by plotting the 1/4T fluence values on Figure 2 of Regulatory Guide 1.99 and using the material specific Cu wt. percent values.

(d) Surveillance data (deemed credible and non-credible per Appendix A of WCAP-18242-NP) from Table 5-12 of WCAP-16001 were used for Unit 2 Position 2.2 USE projections. Regulatory Guide 1.99, Position 2.2 indicates that an upper bound line drawn parallel to the existing lines (in Figure 2 of the Regulatory Guide) through the surveillance data points should be used in preference to the existing graph lines for determining the decrease in USE. Credibility Criterion 3 in the Discussion Section of Regulatory Guide 1.99 indicates that even if the surveillance data are not considered credible for determination of ΔRT_{NDT}, “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 E 185-82.” Thus, the surveillance data may be used for Unit 2 USE projections.

(e) These weld materials were previously addressed by EMA Report BAW-2494 for 48 EFPY. EMAs for these materials have been generated.

Table 4.2.2-7 Reactor Vessel Weld Locations and 80-Year Fluence Projections

RV Material	Material ID and /or Heat Number	(IS) Inside Wetted Surface Fluence or (*) clad/base metal n/cm^2 E> 1.0 MeV)
Unit 1, 80 Year Fluence (E > 1.0 MeV)		
Nozzle Shell to Outlet Nozzle Forging Welds	SA-1493 (Wire Ht. 8T1762)	(IS) 1.50E+18
	SA-1494 (Wire Ht. 8T1554B)	(IS) 1.50E+18
Nozzle Shell to Inlet Nozzle Forging Welds	SA-1526 (Wire Ht. 299L44)	(IS) 1.50E+18
	SA-1580 (Wire Ht. 8T1762)	(IS) 1.50E+18
Nozzle Shell to Intermediate Shell Circ. Weld	J726 (Wire Ht. 25017)	(*) 7.98E+18
Intermediate Shell Long. Welds (Both)	SA-1494 (Wire Ht. 8T1554)	(*)1.33E+19
Intermediate Shell to Lower Shell Circ. Weld (ID 40%	SA-1585 (Wire Ht. 72445)	(*)6.67E+19
Intermediate Shell to Lower Shell Circ. Weld (OD 60%)	SA-1650 (Wire Ht. 72445)	NA
Lower Shell Long. Weld (1)	SA-1494 (Wire Ht. 8T1554)	(*)1.34E+19
Lower Shell Long. Weld (2)	SA-1526 (Wire Ht. 299L44)	(*)1.34E+19
Unit 2, 80 Year Fluence (E > 1.0 MeV)		
Nozzle Shell to Outlet Nozzle Forging Welds	Rotterdam	(IS) 1.50E+18
Nozzle Shell to Inlet Nozzle Forging Welds	WF-4 (Wire Ht. 8T1762)	(IS) 1.50E+18
	WF-8 (Wire Ht. 8T1762)	(IS) 1.50E+18
Nozzle Shell to Intermediate Shell Circ. Weld	L737 (Wire Ht. 4275)	(*) 9.21E+18
Intermediate Shell Long. Weld (1), and (2) (100% and OD 50%)	SA-1585 (Wire Ht. 72445)	(*) 1.36E+19
Intermediate Shell Long. Weld (2) (ID 50%)	WF-4 (Wire Ht. 8T1762)	(*) 1.36E+19

Table 4.2.2-7 Reactor Vessel Weld Locations and 80-Year Fluence Projections

RV Material	Material ID and /or Heat Number	(IS) Inside Wetted Surface Fluence or (*) clad/base metal n/cm^2 E> 1.0 MeV)
Intermediate Shell to Lower Shell Circ. Weld	R3008 (Wire Ht. 0227)	(*) 7.67E+19
Lower Shell Long. Weld (Both)	WF-4 (Wire Ht. 8T1762)	(*) 1.37E+19

Note: No Surry Unit 2 Outlet Nozzle to Upper Shell weld data is available. Generic chemistry values were taken from Regulatory Guide 1.99, Revision 2. The initial RT_{NDT} value was determined using ASME Code, Section III, minimum criteria and BTP 5-3, Position 1.1 guidance. ASME Code, Section III, minimum criteria require measured data; thus, σ_u= 0°F. The initial USE value was determined using results from the first surveillance capsule removed and tested from the Surry Unit 2 RV and BTP 5-3, Position 2.1 guidance.

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 overcooling of the inside surface of the vessel wall followed by repressurization, significant degradation of vessel material toughness caused by radiation embrittlement, and the presence of a critical-size defect anywhere within the vessel wall.

10 CFR 50.61(b)(1) (Reference 1.7-15) provides rules for protection against PTS events for pressurized water reactors. 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 analyses, evaluated for 48 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 Regulatory Guide 1.99. 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 Regulatory Guide 1.99 (Sections 1.1 and 2.1, respectively), using the copper and

nickel content of the Units 1 and 2 beltline materials, and subsequent period of extended operation fluence projections.

These accepted methods were used with the surface fluence values above to calculate the following RT_{PTS} values for the Units 1 and 2 RV materials at 68 EFPY. The subsequent period of extended operation RT_{PTS} calculations are summarized in Table 4.2.3-1 and Table 4.2.3-2 for Units 1 and 2, respectively.

PWROG-16045-NP, summarizes the results and methodologies used in the determination of the unirradiated nil ductility transition temperature (RT_{NDT}) for the Unit 1 and Unit 2 RV materials.

Appendix E of WCAP-18242-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.

All of the beltline materials in the Unit 1 and Unit 2 RV are below the RT_{PTS} screening criteria values of 270°F for base metal and longitudinal welds, and 300°F for circumferentially oriented welds through the subsequent period of extended operation (68 EFPY). It is recognized in SECY-82-465, “Pressurized Thermal Shock (PTS)” (Reference 4.8-30), Enclosure A, that the RT_{PTS} screening criteria values of 270°F for base metal and longitudinal welds, and 300°F for circumferentially oriented welds are applicable to cylindrical beltline materials. The adjusted reference temperatures for all extended beltline materials are well below 270°F.

The Units 1 and 2 limiting RT_{PTS} value for base metal or longitudinal weld materials at 68 EFPY is 253.2°F (see and Table 4.2.3-2), which applies to Unit 1 Lower Shell Longitudinal Weld L2 Heat # 299L44 (using credible surveillance data). The Units 1 and 2 limiting RT_{PTS} value for circumferentially oriented welds at 68 EFPY is 229.8°F (see and Table 4.2.3-2), which applies to the Unit 1 Intermediate to Lower Shell Circumferential Weld Heat # 72445.

Appendix E of WCAP-18242-NP provides RT_{PTS} calculations for the nozzle materials. The Units 1 and 2 materials remain below the 10 CFR 50.61 screening criteria.

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.

Table 4.2.3-1 Calculation of Unit 1 RT_{PTS} Values for 68 EFPY at the Clad/Base Metal Interface

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[a]	Wt.% Ni[a]	CF[a] (°F)	Surface Fluence[b] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[b]	$RT_{NDT(U)}$[c] (°F)	ΔRT_{NDT}[d] (°F)	σ_U[c] (°F)	σ_Δ[e] (°F)	Margin (°F)	RT_{PTS}[f] (°F)
RV Beltline Materials												
Upper Shell Forging 122V109VA1	1.1	0.11	0.74	76.1	0.754	0.921	40	70.1	0	17	34	144.1
Upper to Intermediate Shell Circumferential Weld (Heat # 25017)	1.1	0.33	0.1	152	0.754	0.921	0	140	20	28	68.8	208.8
Intermediate Shell Plate C4326-1	1.1	0.11	0.55	73.5	6.29	1.445	10	106.2	0	17	34	150.2
Intermediate Shell Plate C4326-2	1.1	0.11	0.55	73.5	6.29	1.445	11.4	106.2	0	17	34	151.6
Intermediate Shell Longitudinal Welds L3 and L4 (Heat # 8T1554)	1.1	0.16	0.57	167	1.25	1.062	-48.6	177.4	18	28	66.6	195.4
Intermediate to Lower Shell Circumferential Weld (Heat # 72445)	1.1	0.22	0.54	167	6.31	1.445	-72.5	241.4	12	28	60.9	229.8
Using credible surveillance data	*2.1*	- - -	- - -	*167*	*6.31*	*1.445*	*-72.5*	*241.4*	*12*	*28*	*60.9*	*229.8*
Lower Shell Plate C4415-1	1.1	0.102	0.493	66.6	6.35	1.447	20	96.3	0	17	34	150.3
Using credible surveillance data	*2.1*	- - -	- - -	*83.1*	*6.35*	*1.447*	*20*	*120.2*	*0*	*8.5*	*17*	*157.2*
Lower Shell Plate C4415-2	1.1	0.11	0.5	73	6.35	1.447	4.6	105.6	0	17	34	144.2
Using credible surveillance data	*2.1*	- - -	- - -	*83.1*	*6.35*	*1.447*	*4.6*	*120.2*	*0*	*8.5*	*17*	*141.8*
Lower Shell Longitudinal Weld L1 (Heat # 8T1554)	1.1	0.16	0.57	167	1.26	1.064	-48.6	177.8	18	28	66.6	195.7
Lower Shell Longitudinal Weld L2 (Heat # 299L44)	1.1	0.34	0.68	220.6	1.26	1.064	-74.3	234.8	12.8	28	61.6	222.1
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*1.26*	*1.064*	*-74.3*	*265.9*	*12.8*	*28*	*61.6*	*253.2*

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	Surface Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[(b)]	$RT_{NDT(U)}$[(c)] (°F)	ΔRT_{NDT}[(d)] (°F)	σ_U[(c)] (°F)	σ_Δ[(e)] (°F)	Margin (°F)	RT_{PT}[(f)]$_S$ (°F)
RV Extended Beltline Materials												
Inlet Nozzle 1 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.0304	0.221	-7	48.8	20.6	24.4	63.9	105.7
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.0304*	*0.221*	*-7*	*55.3*	*20.6*	*14*	*49.8*	*98.1*
Inlet Nozzle 2 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.00784	0.093	-7	0.0 (20.4)	20.6	0	41.2	34.2
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.00784*	*0.093*	*-7*	*0.0 (23.2)*	*20.6*	*0*	*41.2*	*34.2*
Inlet Nozzle 3 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.0109	0.116	-7	25.6	20.6	12.8	48.5	67.2
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.0109*	*0.116*	*-7*	*29*	*20.6*	*14*	*49.8*	*71.8*
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0304	0.221	-4.9	33.7	19.7	16.9	51.9	80.7
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00784	0.093	-4.9	0.0 (14.1)	19.7	0	39.4	34.5
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0109	0.116	-4.9	17.7	19.7	0	43.2	56.0
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00813	0.095	-4.9	0.0 (14.5)	19.7	0	39.4	34.5
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00586	0.075	-4.9	0.0 (11.5)	19.7	0	39.4	34.5
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0227	0.186	-4.9	28.3	19.7	14.2	48.5	72

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	Surface Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[(b)]	$RT_{NDT(U)}$[(c)] (°F)	ΔRT_{NDT}[(d)] (°F)	σ_U[(c)] (°F)	σ_Δ[(e)] (°F)	Margin (°F)	RT_{PTS}[(f)] (°F)
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.00813	0.095	-4.9	0.0 (13.7)	19.7	0	39.4	34.5
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.00586	0.075	-4.9	0.0 (10.8)	19.7	0	39.4	34.5
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.0227	0.186	-4.9	26.8	19.7	13.4	47.6	69.5
Inlet Nozzle 1 (Heat # 9-4787)	1.1	0.159	0.85	123.5	0.0304	0.221	10.3	27.3	0	13.7	27.3	65
Inlet Nozzle 2 (Heat # 9-5078)	1.1	0.159	0.87	123.7	0.00784	0.093	11.6	0.0 (11.5)	0	0	0	11.6
Inlet Nozzle 3 (Heat # 9-4819)	1.1	0.159	0.84	123.4	0.0109	0.116	-47.2	14.3	0	7.2	14.3	-18.5
Outlet Nozzle 1 (Heat # 9-4825-1)	1.1	0.159	0.85	123.5	0.00813	0.095	-44.9	0.0 (11.7)	0	0	0	-44.9
Outlet Nozzle 2 (Heat # 9-4762)	1.1	0.159	0.83	123.3	0.00586	0.075	-87.5	0.0 (9.3)	0	0	0	-87.5
Outlet Nozzle 3 (Heat # 9-4788)	1.1	0.159	0.84	123.4	0.0227	0.186	-50.2	0.0 (22.9)	0	11.5	22.9	-4.3

Notes:

(a) Chemical composition values taken from Table 4.2.2-1 and Table 4.2.2-2. Chemistry factor values taken from Table 3-10 of WCAP-18242-NP.

(b) Surface fluence values taken from Section 2 of WCAP-18242-NP. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.

(c) Initial RT_{NDT} and σ_u values are taken from Table 4.2.2-1 and Table 4.2.2-2.

(d) Per NRC RIS 2014-11, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components," (Reference 4.8-31), embrittlement effects may be neglected for materials with fluence values less than 1.0 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1.0 x 10^{17} n/$cm^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) Per Appendix A of WCAP-18242-NP, all Unit 1 surveillance data was deemed credible. Per the guidance of 10 CFR 50.61, the base metal σ_Δ = 17°F for Position 1.1, and σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also per 10 CFR 50.61, the weld metal σ_Δ = 28°F for Position 1.1, and with credible surveillance data σ_Δ = 14°F for Position 2.1. However, σ_Δ need not exceed 0.5* ΔRT_{NDT}. For welds utilizing initial RT_{NDT} values based on BAW-2308, σ_Δ = 28°F per BAW-2308, (Revision 1-A), SE and BAW-2308, (Revision 2-A) SE, "Final Safety Evaluation for Pressurized Water Reactors Owners Group (PWROG) Topical Report (TR) BAW-2308, (Revision 2), 'Initial RT_{NDT} of Linde 80 Weld Materials"' (Reference 4.8-32).

(f) RT_{PTS} values calculated in accordance with 10 CFR 50.61 methodology.

Table 4.2.3-2 Calculation of Unit 2 RT_{PTS} Values for 68 EFPY at the Clad/Base Metal Interface

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	Surface Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[(b)]	$RT_{NDT(U)}$[(c)] (°F)	ΔRT_{NDT}[(d)] (°F)	σ_U[(c)] (°F)	σ_Δ[(e)] (°F)	Margin (°F)	RT_{PTS}[(f)] (°F)
RV Beltline Materials												
Upper Shell Forging 123V303VA1	1.1	0.11	0.72	75.8	0.865	0.959	30	72.7	0	17	34	136.7
Upper to Intermediate Shell Circumferential Weld (Heat # 4275)	1.1	0.35	0.1	160.5	0.865	0.959	0	154	20	28	68.8	222.8
Intermediate Shell Plate C4331-2	1.1	0.12	0.6	83	7.2	1.467	15	121.8	0	17	34	170.8
Intermediate Shell Plate C4339-2	1.1	0.11	0.54	73.4	7.2	1.467	7.8	107.7	0	17	34	149.5
Using non-credible surveillance data	*2.1*	- - -	- - -	*75.7*	*7.2*	*1.467*	*7.8*	*111.1*	*0*	*17*	*34*	*152.9*
Intermediate Shell Longitudinal Welds L3 and L4 (OD 50%) (Heat # 72445)	1.1	0.22	0.54	167	1.29	1.071	-72.5	178.8	12	28	60.9	167.3
Using credible surveillance data	*2.1*	- - -	- - -	*167*	*1.29*	*1.071*	*-72.5*	*178.8*	*12*	*28*	*60.9*	*167.3*
Intermediate Shell Longitudinal Weld L4 (ID 50%) (Heat # 8T1762)	1.1	0.19	0.57	167	1.29	1.071	-48.6	178.8	18	28	66.6	196.8
Intermediate to Lower Shell Circumferential Weld (Heat # 0227)	1.1	0.187	0.545	147.5	7.22	1.468	0	216.5	0	28	56	272.5

Table 4.2.3-2 Calculation of Unit 2 RT_{PTS} Values for 68 EFPY at the Clad/Base Metal Interface

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[a]	Wt.% Ni[a]	CF[a] (°F)	Surface Fluence[b] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[b]	$RT_{NDT(U)}$[c] (°F)	ΔRT_{NDT}[d] (°F)	σ_U[c] (°F)	σ_Δ[e] (°F)	Margin (°F)	RT_{PTS}[f] (°F)
RV Beltline Materials												
Using credible surveillance data	*2.1*	- - -	- - -	*132.5*	*7.22*	*1.468*	*0*	*194.5*	*0*	*14*	*28*	*222.5*
Lower Shell Plate C4208-2	1.1	0.15	0.55	107.3	7.26	1.469	-30	157.6	0	17	34	161.6
Lower Shell Plate C4339-1	1.1	0.107	0.53	70.8	7.26	1.469	-4.4	104	0	17	34	133.6
Using non-credible surveillance data	*2.1*	- - -	- - -	*75.7*	*7.26*	*1.469*	*-4.4*	*111.2*	*0*	*17*	*34*	*140.8*
Lower Shell Longitudinal Welds L1 and L2 (Heat # 8T1762)	1.1	0.19	0.57	167	1.3	1.073	-48.6	179.2	18	28	66.6	197.2

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[a]	Wt.% Ni[a]	CF[a] (°F)	Surface Fluence[b] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[b]	$RT_{NDT(U)}$[c] (°F)	ΔRT_{NDT}[d] (°F)	σ_U[c] (°F)	σ_Δ[e] (°F)	Margin (°F)	RT_{PTS}[f] (°F)
RV Extended Beltline Materials												
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.034	0.236	-4.9	36	19.7	18	53.4	84.4
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00784	0.093	-4.9	0.0 (14.1)	19.7	0	39.4	34.5
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762	1.1	0.19	0.57	152.4	0.0107	0.115	-4.9	0.0 (17.5)	19.7	8.7	43.1	55.7
Outlet Nozzle 1 to Upper Shell Weld (Rotterdam)	1.1	0.35	1	272	0.00796	0.094	30	0.0 (25.5)	0	0.0	0.0	30.0
Outlet Nozzle 2 to Upper Shell Weld (Rotterdam)	1.1	0.35	1	272	0.00585	0.075	30	0.0 (20.5)	0	0	0	30
Outlet Nozzle 3 to Upper Shell Weld (Rotterdam)	1.1	0.35	1	272	0.0253	0.199	30	54	0	27	54	138
Inlet Nozzle 1 (Heat # 9-5104)	1.1	0.159	0.84	123.4	0.034	0.236	-29.7	29.1	0	14.6	29.1	28.6
Inlet Nozzle 2 (Heat # 9-4815)	1.1	0.159	0.87	123.7	0.00784	0.093	4.5	0.0 (11.5)	0	0	0	4.5
Inlet Nozzle 3 (Heat # 9-5205)	1.1	0.159	0.86	123.6	0.0107	0.115	6.5	14.2	0	7.1	14.2	34.9
Outlet Nozzle 1 (Heat # 9-4825-2)	1.1	0.159	0.85	123.5	0.00796	0.094	-58.1	0.0 (11.6)	0	0	0	-58.1
Outlet Nozzle 2 (Heat # 9-5086-1)	1.1	0.159	0.86	123.6	0.00585	0.075	-26.6	0.0 (9.3)	0	0	0	-26.6
Outlet Nozzle 3 (Heat # 9-5086-2)	1.1	0.159	0.87	123.7	0.0253	0.199	-33.8	24.6	0	12.3	24.6	15.3

Notes:

(a) Chemical composition values taken from Table 4.2.2-3 and Table 4.2.2-4. Chemistry factor values taken from Table 3-12 of WCAP-18242-NP.

(b) Surface fluence values taken from Section 2 of WCAP-18242-NP. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.

(c) Initial RT_{NDT} and σ_u values taken from Table 4.2.2-3 and Table 4.2.2-4.

(d) Per NRC RIS 2014-11, embrittlement effects may be neglected for materials with fluence values less than 1.0 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1.0 x 10^{17} n/cm$^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) Per Appendix A of WCAP-18242-NP, the surveillance plate data were deemed non-credible, whereas the surveillance data for the weld materials were deemed credible. Per the guidance of 10 CFR 50.61, the base metal σ_u = 17°F for Position 1.1 and for Position 2.1 with non- credible surveillance data. Per 10 CFR 50.61, the weld metal σ_u = 28°F for Position 1.1, and with credible surveillance data σ_I = 14°F for Position 2.1. However, σ_u need not exceed 0.5* ΔRT_{NDT}. For welds utilizing initial RT_{NDT} values based on BAW-2308, (Revisions 1-A SE and 2-A SE), σ_u = 28°F.

(f) RT_{PTS} values calculated in accordance with 10 CFR 50.61 methodology.

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 1.99 provides the methodology for determining the ART of the limiting material. The initial nil-ductility reference temperature, 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-16045-NP, which includes the generally accepted techniques outlined in:

- ASME Code, Section III, Paragraph NB 2331,
- Branch Technical Position 5-3,
- BWRVIP-173-A, "BWR Vessel and Internals Project: Evaluation of Chemistry Data for BWR Vessel Nozzle Forging Materials" (Reference 4.8-33), and
- BAW-2313.

10 CFR 50, Appendix G, defines the fracture toughness requirements for the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb 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 (unirradiated) reference temperature (Initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (ΔRT_{NDT}), and a margin (M) term.

Since the ΔRT_{NDT} value is a function of 48 EFPY 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:

As described in Section 4.2.1, 68 EFPY fluence values were determined for the Units 1 and 2 RV beltline and extended beltline components. These 68 EFPY 1/4T fluence values were used to compute the ART values of Units 1 and 2, in accordance with Regulatory Guide 1.99.

Table 4.2.4-1 through 4.2.4-9 summarize the nozzle, and 1/4T ART calculations for Units 1 and 2 at 48 and 68 EFPY. The 3/4T ART values are included in WCAP-18242-NP. The limiting 48 EFPY and 68 EFPY ART values for Units 1 and 2 apply to the Unit 2 Intermediate to Lower Shell Circumferential Weld (using surveillance data).

The inlet and outlet nozzle forging ARTs are necessary to perform a nozzle corner fracture mechanics analysis. The nozzle forging ART calculations utilize the postulated nozzle forging surface 1/4T flaw fluence values in order to provide a conservative estimate of the fluence at the limiting nozzle corner location. The nozzle ART values are also considered herein because the nozzle fluence values for some nozzle materials exceed 1.0×10^{17} n/cm^2 (E > 1.0 MeV), and thus all of the nozzle forgings are considered part of the extended beltline for conservatism. Since the surface fluence values are utilized for the ART calculations for the nozzle forging materials, the nozzle forgings are omitted from 1/4T ART calculations.

Table 4.2.4-9 compares the TLAA limiting ART values at 48 EFPY and 68 EFPY to the limiting ART values used in development of the existing 48 EFPY P-T limit curves documented in WCAP-14177, "Surry Power Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation" (Reference 4.8-34). The limiting ART values used to develop the existing P-T limit curves are summarized in Table 4.2.4-9. As shown in Table 4.2.4-9, the TLAA limiting ART values at 48 EFPY and 68 EFPY are less than the limiting ART values used to develop the existing P-T limit curves. Appendix B of WCAP-18243-NP shows that the PT curves for the nozzles lie above and to the left of the PT curves for the beltline materials. Thus, the PT curves for the beltline materials are bounding through the subsequent period of extended operation.

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. They may be used as inputs to 68 EFPY P-T limits for the subsequent period of extended operation.

Table 4.2.4-1 Calculation of the Unit 1 Nozzle ART Values at the Surface Location for 48 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	Surface Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[(b)]	$RT_{NDT}(U)$[(c)] (°F)	ΔRT_{NDT}[(d)] (°F)	σ_I[(c)] (°F)	σ_Δ[(e)] (°F)	Margin (°F)	ART[(f)] (°F)
Inlet Nozzle 1 (Heat # 9-4787)	1.1	0.159	0.85	123.5	0.00870	0.100	10.3	0.0 (12.3)	0.0	0.0	0.0	10.3
Inlet Nozzle 2 (Heat # 9-5078)	1.1	0.159	0.87	123.7	0.00219	0.035	11.6	0.0 (4.4)	0.0	0.0	0.0	11.6
Inlet Nozzle 3 (Heat # 9-4819)	1.1	0.159	0.84	123.4	0.00306	0.046	-47.2	0.0 (5.7)	0.0	0.0	0.0	-47.2
Outlet Nozzle 1 (Heat # 9-4825-1)	1.1	0.159	0.85	123.5	0.00237	0.038	-44.9	0.0 (4.6)	0.0	0.0	0.0	-44.9
Outlet Nozzle 2 (Heat # 9-4762)	1.1	0.159	0.83	123.3	0.0017	0.029	-87.5	0.0 (3.5)	0.0	0.0	0.0	-87.5
Outlet Nozzle 3 (Heat # 9-4788)	1.1	0.159	0.84	123.4	0.00672	0.083	-50.2	0.0 (10.3)	0.0	0.0	0.0	-50.2

Notes:

(a) Chemical composition data taken from Table 4.2.2-1 and Table 4.2.2-2. Chemistry factor values taken from Table 3-10 of WCAP-18242-NP.

(b) Surface fluence values were from WCAP-18-242-NP. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-2

(d) Per NRC RIS 2014-11, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components," embrittlement effects may be neglected for materials with fluence values less than 1.0 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1.0 x 10^{17} n/cm$^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) Per the guidance of Regulatory Guide 1.99, the base metal σ_Δ = 17°F for Position 1.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}.

(f) ART values calculated in accordance with Regulatory Guide 1.99, Revision 2 methodology.

Table 4.2.4-2 Calculation of the Unit 1 ART Values at the 1/4T Location for 48 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu(a)	Wt.% Ni(a)	CF(a) (°F)	1/4T Fluence(b) (x 10^{19} n/cm², E > 1.0 MeV)	1/4T FF(b)	$RT_{NDT}(U)$ (c) (°F)	ΔRT_{NDT} (d) (°F)	σ_I(c) (°F)	σ_Δ (e) (°F)	Margin (°F)	1/4T ART(f) (°F)
RV Beltline Materials												
Upper Shell Forging 122V109VA1	1.1	0.11	0.74	76.1	0.329	0.695	40	52.9	0.0	17.0	34.0	126.9
Upper to Intermediate Shell Circumferential Weld (Heat # 25017)	1.1	0.33	0.10	152	0.329	0.695	0	105.6	20.0	28.0	68.8	174.4
Intermediate Shell Plate C4326-1	1.1	0.11	0.55	73.5	2.79	1.274	10	93.6	0.0	17.0	34.0	137.6
Intermediate Shell Plate C4326-2	1.1	0.11	0.55	73.5	2.79	1.274	11.4	93.6	0.0	17.0	34.0	139
Intermediate Shell Longitudinal Welds L3 and L4 (Heat # 8T1554)	1.1	0.16	0.57	167	0.537	0.826	-48.6	138	18.0	28.0	66.6	156.0
Intermediate to Lower Shell Circumferential Weld (Heat # 72445)	1.1	0.22	0.54	167	2.81	1.275	-72.5	212.9	12.0	28.0	60.9	201.3
Using credible surveillance data	*2.1*	- - -	- - -	*167*	*2.81*	*1.275*	*-72.5*	*212.9*	*12.0*	*28.0*	*60.9*	*201.3*
Lower Shell Plate C4415-1	1.1	0.102	0.493	66.6	2.82	1.276	20	85	0.0	17.0	34.0	139
Using credible surveillance data	*2.1*	- - -	- - -	*83.1*	*2.82*	*1.276*	*20*	*106.0*	*0.0*	*8.5*	*17.0*	*143.0*
Lower Shell Plate C4415-2	1.1	0.11	0.5	73	2.82	1.276	4.6	93.1	0.0	17.0	34.0	131.7
Using credible surveillance data	*2.1*	- - -	- - -	*83.1*	*2.82*	*1.276*	*4.6*	*106.0*	*0.0*	*8.5*	*17.0*	*127.6*
Lower Shell Longitudinal Weld L1 (Heat # 8T1554)	1.1	0.16	0.57	167	0.542	0.829	-48.6	138.4	18.0	28.0	66.6	156.4
Lower Shell Longitudinal Weld L2 (Heat # 299L44)	1.1	0.34	0.68	220.6	0.542	0.829	-74.3	182.8	12.8	28.0	61.6	170.1
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.542*	*0.829*	*-74.3*	*207.0*	*12.8*	*28.0*	*61.6*	*194.3*

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF[(b)]	RT_{NDT}(U)[(c)] (°F)	ΔRT_{NDT}[(d)] (°F)	σ_I[(c)] (°F)	σ_Δ[(e)] (°F)	Margin (°F)	1/4T ART[(f)] (°F)
RV Extended Beltline Materials												
Inlet Nozzle 1 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.0131	0.132	-7	29	20.6	14.5	50.4	72.4
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.0131*	*0.132*	*-7*	*32.9*	*20.6*	*14.0*	*49.8*	*75.7*
Inlet Nozzle 2 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.00330	0.049	-7	0.0 (10.8)	20.6	0.0	41.2	34.2
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.00330*	*0.049*	*-7*	*0.0 (12.2)*	*20.6*	*0.0*	*41.2*	*34.2*
Inlet Nozzle 3 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.00462	0.063	-7	0.0 (13.9)	20.6	0.0	41.2	34.2
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.00462*	*0.063*	*-7*	*0.0 (15.8)*	*20.6*	*0.0*	*41.2*	*34.2*
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0131	0.132	-4.9	20.1	19.7	0.0	44.2	59.4
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00330	0.049	-4.9	0.0 (7.5)	19.7	0.0	39.4	34.5
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00462	0.063	-4.9	0.0 (9.6)	19.7	0.0	39.4	34.5
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00345	0.051	-4.9	0.0 (7.7)	19.7	0.0	39.4	34.5
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00247	0.039	-4.9	0.0 (5.9)	19.7	0.0	39.4	34.5
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00981	0.108	-4.9	16.5	19.7	0.0	42.7	34.5
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.00345	0.051	-4.9	0.0 (7.3)	19.7	0.0	39.4	34.5
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.00247	0.039	-4.9	0.0 (5.6)	19.7	0.0	39.4	34.5
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.00981	0.108	-4.9	15.6	19.7	7.8	42.4	53.0

Notes:

(a) Chemical composition data taken from Table 4.2.2-1 and Table 4.2.2-2. Chemistry factor values taken from Table 3-10 of WCAP-18242-NP.

(b) 48 EFPY surface fluence values were from WCAP-18242-NP. The 1/4T fluence and 1/4T FF were calculated using the Regulatory Guide 1.99 correlations and the Unit 1 RV wall thickness of 8.05 inches.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-1 and Table 4.2.2-2.

(d) Per NRC RIS 2014-11, “Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components,” embrittlement effects may be neglected for materials with fluence values less than 1.0 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1.0 x 10^{17} n/$cm^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) As summarized in Appendix A of WCAP-18242-NP, all surveillance data for Unit 1 were deemed credible. Per the guidance of Regulatory Guide 1.99, the base metal σ_Δ = 17°F for Position 1.1, and σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also per Regulatory Guide 1.99, the weld metal σ_Δ = 28°F for Position 1.1, and with credible surveillance data σ_Δ = 14°F for Position 2.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}. For welds utilizing initial RT_{NDT} values based on BAW-2308, (Revisions 1 A SE and 2 A SE), σ_Δ = 28°F.

(f) ART values calculated in accordance with Regulatory Guide 1.99, Revision 2 methodology.

Table 4.2.4-3 Calculation of the Unit 2 Nozzle ART Values at the Surface Location for 48 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	Surface Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[(b)]	$RT_{NDT}(U)$ [(c)] (°F)	ΔRT_{NDT} [(d)] (°F)	σ_I[(c)] (°F)	σ_Δ [(e)] (°F)	Margin (°F)	ART[(f)] (°F)
Inlet Nozzle 1 (Heat # 9-5104)	1.1	0.159	0.84	123.4	0.00935	0.105	-29.7	0.0 (12.9)	0.0	0.0	0.0	-29.7
Inlet Nozzle 2 (Heat # 9-4815)	1.1	0.159	0.87	123.7	0.00223	0.036	4.5	0.0 (4.4)	0.0	0.0	0.0	4.5
Inlet Nozzle 3 (Heat # 9-5205)	1.1	0.159	0.86	123.6	0.00304	0.046	6.5	0.0 (5.7)	0.0	0.0	0.0	6.5
Outlet Nozzle 1 (Heat # 9-4825-2)	1.1	0.159	0.85	123.5	0.00235	0.037	-58.1	0.0 (4.6)	0.0	0.0	0.0	-58.1
Outlet Nozzle 2 (Heat # 9-5086-1)	1.1	0.159	0.86	123.6	0.00172	0.029	-26.6	0.0 (3.6)	0.0	0.0	0.0	-26.6
Outlet Nozzle 3 (Heat # 9-5086-2)	1.1	0.159	0.87	123.7	0.00723	0.088	-33.8	0.0 (10.8)	0.0	0.0	0.0	-33.8

Notes:

(a) Chemical composition values taken from Table 4.2.2-3 and Table 4.2.2-4. Chemistry factor values taken from Table 3-12 of WCAP-18242-NP.

(b) Surface fluence values were from WCAP-18242-NP. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-4.

(d) Per NRC RIS 2014-11, “Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components,” embrittlement effects may be neglected for materials with fluence values less than 1 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1 x 10^{17} n/cm$^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) Per the guidance of Regulatory Guide 1.99, the base metal σ_Δ = 17°F for Position 1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}.

(f) ART values calculated in accordance with Regulatory Guide 1.99, Revision 2 methodology.

Table 4.2.4-4 Calculation of the Unit 2 ART Values at the 1/4T Location for 48 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF[(b)]	$RT_{NDT}(U)$ [(c)] (°F)	ΔRT_{NDT} [(d)] (°F)	σ_I[(c)] (°F)	σ_Δ [(e)] (°F)	Margin (°F)	1/4T ART[(f)] (°F)
RV Beltline Materials												
Upper Shell Forging 123V303VA1	1.1	0.11	0.72	75.8	0.362	0.719	30	54.5	0.0	17.0	34.0	118.5
Upper to Intermediate Shell Circumferential Weld (Heat # 4275)	1.1	0.35	0.10	160.5	0.362	0.719	0	115.4	20.0	28.0	68.8	184.2
Intermediate Shell Plate C4331-2	1.1	0.12	0.6	83	3.07	1.296	15	107.6	0.0	17.0	34.0	156.6
Intermediate Shell Plate C4339-2	1.1	0.11	0.54	73.4	3.07	1.296	7.8	95.1	0.0	17.0	34.0	136.9
Using non-credible surveillance data	*2.1*	- - -	- - -	*75.7*	*3.07*	*1.296*	*7.8*	*98.1*	*0.0*	*17.0*	*34.0*	*139.9*
Intermediate Shell Longitudinal Welds L3 and L4 (OD 50%) (Heat # 72445)	1.1	0.22	0.54	167	0.563	0.839	-72.5	140.2	12.0	28.0	60.9	128.6
Using credible surveillance data	*2.1*	- - -	- - -	*167*	*0.563*	*0.839*	*-72.5*	*140.2*	*12.0*	*28.0*	*60.9*	*128.6*
Intermediate Shell Longitudinal Weld L4 (ID 50%) (Heat # 8T1762)	1.1	0.19	0.57	167	0.563	0.839	-48.6	140.2	18.0	28.0	66.6	158.2
Intermediate to Lower Shell Circumferential Weld (Heat # 0227)	1.1	0.187	0.545	147.5	3.07	1.296	0	191.2	0.0	28.0	56.0	247.2
Using credible surveillance data	*2.1*	- - -	- - -	*132.5*	*3.07*	*1.296*	*0*	*171.8*	*0.0*	*14.0*	*28.0*	*199.8*
Lower Shell Plate C4208-2	1.1	0.15	0.55	107.3	3.09	1.298	-30	139.3	0.0	17.0	34.0	143.3
Lower Shell Plate C4339-1	1.1	0.107	0.53	70.8	3.09	1.298	-4.4	91.9	0.0	17.0	34.0	121.5
Using non-credible surveillance data	*2.1*	- - -	- - -	*75.7*	*3.09*	*1.298*	*-4.4*	*98.2*	*0.0*	*17.0*	*34.0*	*127.8*
Lower Shell Longitudinal Welds L1 and L2 (Heat # 8T1762)	1.1	0.19	0.57	167	0.567	0.841	-48.6	140.5	18.0	28.0	66.6	158.5

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% $Cu^{(a)}$	Wt.% $Ni^{(a)}$	$CF^{(a)}$ (°F)	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T $FF^{(b)}$	$RT_{NDT}(U)$ [(c)] (°F)	ΔRT_{NDT} [(d)] (°F)	σ_I[(c)] (°F)	σ_Δ [(e)] (°F)	Margin (°F)	1/4T $ART^{(f)}$ (°F)
RV Extended Beltline Materials												
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0141	0.138	-4.9	0.0 (21.0)	19.7	0.0	39.4	34.5
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00336	0.050	-4.9	0.0 (7.6)	19.7	0.0	39.4	34.5
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0059	0.063	-4.9	0.0 (9.6)	19.7	0.0	39.4	34.5
Outlet Nozzle 1 to Upper Shell Weld (Rotterdam)	1.1	0.35	1	272	0.00342	0.050	30	0.0 (13.7)	0.0	0.0	0.0	30
Outlet Nozzle 2 to Upper Shell Weld (Rotterdam)	1.1	0.35	1	272	0.0025	0.039	30	0.0 (10.7)	0.0	0.0	0.0	30
Outlet Nozzle 3 to Upper Shell Weld (Rotterdam)	1.1	0.35	1	272	0.0105	0.114	30	30.9	0.0	15.5	30.9	91.9

Notes:

(a) Chemical composition values taken from Table 4.2.2-3 and Table 4.2.2-4. Chemistry factor values taken from Table 3-12 of WCAP-18242-NP.

(b) 48 EFPY surface fluence values were from WCAP-18242-NP. The 1/4T fluence and 1/4T FF were calculated using the Regulatory Guide 1.99, correlations and the Unit 2 RV wall thickness of 8.05 inches.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-3 and Table 4.2.2-4.

(d) Per NRC RIS 2014-11, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components," embrittlement effects may be neglected for materials with fluence values less than 1 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1 x 10^{17} n/cm^2; therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) Per Appendix A of WCAP-18242-NP, the surveillance plate data were deemed non credible, whereas the surveillance data for the weld materials were deemed credible. Per the guidance of Regulatory Guide 1.99, the base metal σ_Δ = 17°F for Position 1.1 and for Position 2.1 with non-credible surveillance data. Also per Regulatory Guide 1.99, the weld metal σ_Δ = 28°F for Position 1.1, and with credible surveillance data σ_Δ = 14°F for Position 2.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}. For welds utilizing initial RT_{NDT} values based on BAW-2308, (Revisions 1-A SE and 2-A SE), σ_Δ = 28°F.

(f) ART values calculated in accordance with Regulatory Guide 1.99, Revision 2 methodology.

Table 4.2.4-5 Calculation of the Unit 1 Nozzle ART Values at the Surface Location for 68 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	Surface Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[(b)]	$RT_{NDT}(U)$ [(c)] (°F)	ΔRT_{NDT} [(d)] (°F)	σ_I[(c)] (°F)	σ_Δ [(e)] (°F)	Margin (°F)	ART[(f)(g)] (°F)
Inlet Nozzle 1 (Heat # 9-4787)	1.1	0.159	0.85	123.5	0.0124	0.127	10.3	15.6	0.0	7.8	15.6	41.6
Inlet Nozzle 2 (Heat # 9-5078)	1.1	0.159	0.87	123.7	0.00322	0.048	11.6	0.0 (5.9)	0.0	0.0	0.0	11.6
Inlet Nozzle 3 (Heat # 9-4819)	1.1	0.159	0.84	123.4	0.00446	0.062	-47.2	0.0 (7.6)	0.0	0.0	0.0	-47.2
Outlet Nozzle 1 (Heat # 9-4825-1)	1.1	0.159	0.85	123.5	0.00345	0.051	-44.9	0.0 (6.3)	0.0	0.0	0.0	-44.9
Outlet Nozzle 2 (Heat # 9-4762)	1.1	0.159	0.83	123.3	0.00249	0.039	-87.5	0.0 (4.8)	0.0	0.0	0.0	-87.5
Outlet Nozzle 3 (Heat # 9-4788)	1.1	0.159	0.84	123.4	0.00962	0.107	-50.2	0.0 (13.2)	0.0	0.0	0.0	-50.2

Notes:

(a) Chemical composition data taken from Table 4.2.2-1 and Table 4.2.2-2. Chemistry factor values taken from Table 3-10 of WCAP-18242-NP.

(b) Surface fluence values taken from Section 4.2.1. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-2.

(d) Per NRC RIS 2014-11, “Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components,” embrittlement effects may be neglected for materials with fluence values less than 1 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1 x 10^{17} n/cm$^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) Per the guidance of Regulatory Guide 1.99, the base metal σ_Δ = 17°F for Position 1.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}.

(f) Nozzle materials are not limiting for P-T limit curves per WCAP-18243-NP, “Surry Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation” (Reference 4.8-35).

(g) ART values calculated in accordance with Regulatory Guide 1.99, Revision 2 methodology.

Table 4.2.4-6 Calculation of the Unit 1 ART Values at the 1/4T Location for 68 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF[(b)]	$RT_{NDT}(U)$ [(c)] (°F)	ΔRT_{NDT} [(d)] (°F)	σ_I[(c)] (°F)	σ_Δ [(e)] (°F)	Margin (°F)	1/4T ART[(f)] (°F)
RV Beltline Materials												
Upper Shell Forging 122V109VA1	1.1	0.11	0.74	76.1	0.465	0.787	40	59.9	0.0	17.0	34.0	133.9
Upper to Intermediate Shell Circumferential Weld (Heat # 25017)	1.1	0.33	0.10	152	0.465	0.787	0	119.6	20.0	28.0	68.8	188.4
Intermediate Shell Plate C4326-1	1.1	0.11	0.55	73.5	3.88	1.350	10	99.2	0.0	17.0	34.0	143.2
Intermediate Shell Plate C4326-2	1.1	0.11	0.55	73.5	3.88	1.350	11.4	99.2	0.0	17.0	34.0	144.6
Intermediate Shell Longitudinal Welds L3 and L4 (Heat # 8T1554)	1.1	0.16	0.57	167	0.771	0.927	-48.6	154.8	18.0	28.0	66.6	172.8
Intermediate to Lower Shell Circumferential Weld (Heat # 72445)	1.1	0.22	0.54	167	3.89	1.350	-72.5	225.5	12.0	28.0	60.9	213.9
Using credible surveillance data	*2.1*	- - -	- - -	*167*	*3.89*	*1.350*	*-72.5*	*225.5*	*12.0*	*28.0*	*60.9*	*213.9*
Lower Shell Plate C4415-1	1.1	0.102	0.493	66.6	3.92	1.352	20	90	0.0	17.0	34.0	144.0
Using credible surveillance data	*2.1*	- - -	- - -	*83.1*	*3.92*	*1.352*	*20*	*112.3*	*0.0*	*8.5*	*17.0*	*149.3*
Lower Shell Plate C4415-2	1.1	0.11	0.50	73	3.92	1.352	4.6	98.7	0.0	17.0	34.0	137.3
Using credible surveillance data	*2.1*	- - -	- - -	*83.1*	*3.92*	*1.352*	*4.6*	*112.3*	*0.0*	*8.5*	*17.0*	*133.9*
Lower Shell Longitudinal Weld L1 (Heat # 8T1554)	1.1	0.16	0.57	167	0.777	0.929	-48.6	155.2	18.0	28.0	66.6	173.2
Lower Shell Longitudinal Weld L2 (Heat # 299L44)	1.1	0.34	0.68	220.6	0.777	0.929	-74.3	205	12.8	28.0	61.6	192.3

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu(a)	Wt.% Ni(a)	CF(a) (°F)	1/4T Fluence(b) (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF(b)	RT_{NDT}(U) (c)(°F)	ΔRT_{NDT} (d) (°F)	σ_I(c) (°F)	σ_Δ (e) (°F)	Margin (°F)	1/4T ART(f) (°F)
RV Beltline Materials												
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.777*	*0.929*	*-74.3*	*232.1*	*12.8*	*28.0*	*61.6*	*219.4*
RV Extended Beltline Materials												
Inlet Nozzle 1 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.0188	0.165	-7.0	36.5	20.6	18.2	55.0	84.5
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.0188*	*0.165*	-7.0	*41.3*	*20.6*	*14.0*	*49.8*	*84.1*
Inlet Nozzle 2 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.00484	0.065	-7.0	0.0 (14.4)	20.6	0.0	41.2	34.2
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.00484*	*0.065*	-7.0	*0.0 (16.3)*	*20.6*	*0.0*	*41.2*	*34.2*
Inlet Nozzle 3 to Upper Shell Weld (Heat # 299L44)	1.1	0.34	0.68	220.6	0.00672	0.083	-7.0	18.3	20.6	9.2	45.1	56.4
Using credible surveillance data	*2.1*	- - -	- - -	*249.8*	*0.00672*	*0.083*	-7.0	*20.8*	*20.6*	*10.4*	*46.1*	*59.9*
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0188	0.165	-4.9	25.2	19.7	12.6	46.8	67.1
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00484	0.065	-4.9	0.0 (10.0)	19.7	0.0	39.4	34.5
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00672	0.083	-4.9	12.7	19.7	6.3	41.4	49.2
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00502	0.067	-4.9	0.0 (10.2)	19.7	0.0	39.4	34.5
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00362	0.052	-4.9	0.0 (8.0)	19.7	0.0	39.4	34.5
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0140	0.137	-4.9	20.9	19.7	10.5	44.6	60.6
Outlet Nozzle 1 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.00502	0.067	-4.9	0.0 (9.7)	19.7	0	39.4	34.5

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu(a)	Wt.% Ni(a)	CF(a) (°F)	1/4T Fluence(b) (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF(b)	RT_{NDT}(U)(c) (°F)	ΔRT_{NDT} (d) (°F)	σ_I(c) (°F)	σ_Δ (e) (°F)	Margin (°F)	1/4T ART(f) (°F)
RV Extended Beltline Materials												
Outlet Nozzle 2 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.00362	0.052	-4.9	0.0 (7.6)	19.7	0	39.4	34.5
Outlet Nozzle 3 to Upper Shell Weld (Heat # 8T1554B)	1.1	0.16	0.57	143.9	0.0140	0.137	-4.9	19.7	19.7	9.9	44.1	58.9

Notes:

(a) Chemical composition data taken from Table 4.2.2-1 and Table 4.2.2-2. Chemistry factor values taken from Table 3-10 of WCAP-18242-NP.

(b) The 1/4T fluence and 1/4T FF were taken from Table 5-1 of WCAP-18243-NP.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-1 and Table 4.2.2-2.

(d) Per NRC RIS 2014-11, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components," embrittlement effects may be neglected for materials with fluence values less than 1 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1 x 10^{17} n/cm$^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) As summarized in Appendix G of WCAP-18343-NP, all surveillance data for Unit 1 were deemed credible. Per the guidance of Regulatory Guide 1.99 (Revision 2), the base metal σ_Δ = 17°F for Position 1.1, and σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also per Regulatory Guide 1.99 (Revision 2), the weld metal σ_Δ = 28°F for Position 1.1, and with credible surveillance data σ_Δ = 14°F for Position 2.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}. For welds utilizing initial RT_{NDT} values based on BAW-2308, σ_Δ = 28°F

(f) ART values calculated in accordance with Regulatory Guide 1.99 (Revision 2) methodology.

Table 4.2.4-7 Calculation of the Unit 2 ART Nozzle Values at the Surface Location for 68 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu(a)	Wt.% Ni(a)	CF(a) (°F)	Surface Fluence(b) (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF(b)	$RT_{NDT}(U)$ (c) (°F)	ΔRT_{NDT} (d) (°F)	σ_I(c) (°F)	σ_Δ (e) (°F)	Margin (°F)	ART(f)(g) (°F)
Inlet Nozzle 1 Heat # 9-5104)	1.1	0.159	0.84	123.4	0.0139	0.137	-29.7	16.8	0.0	8.4	16.8	4.0
Inlet Nozzle 2 (Heat # 9-4815)	1.1	0.159	0.87	123.7	0.00321	0.048	4.5	0.0 (5.9)	0.0	0.0	0.0	4.5
Inlet Nozzle 3 (Heat # 9-5205)	1.1	0.159	0.86	123.6	0.00437	0.061	6.5	0.0 (7.5)	0.0	0.0	0.0	6.5
Outlet Nozzle 1 (Heat # 9-4825-2)	1.1	0.159	0.85	123.5	0.00338	0.05	-58.1	0.0 (6.2)	0.0	0.0	0.0	-58.1
Outlet Nozzle 2 (Heat # 9-5086-1)	1.1	0.159	0.86	123.6	0.00248	0.039	-26.6	0.0 (4.8)	0.0	0.0	0.0	-26.6
Outlet Nozzle 3 (Heat # 9-5086-2)	1.1	0.159	0.87	123.7	0.0107	0.115	-33.8	14.2	0.0	7.1	14.2	-5.4

Notes:

(a) Chemical composition values taken from Table 4.2.2-3 and Table 4.2.2-4. Chemistry factor values taken from Table 3-12 of WCAP-18242-NP.

(b) Surface fluence values taken from Section 4.2.1. FF = fluence factor = $f^{(0.28-0.10*\log(f))}$.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-4.

(d) Per NRC RIS 2014-11, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components," embrittlement effects may be neglected for materials with fluence values less than 1 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1 x 10^{17} n/cm$^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) Per the guidance of Regulatory Guide 1.99, the base metal σ_Δ = 17°F for Position 1.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}.

(f) Nozzle materials are not limiting for P-T limit curves per WCAP-18243-NP.

(g) ART values calculated in accordance with Regulatory Guide 1.99 (Revision 2) methodology.

Table 4.2.4-8 Calculation of the Unit 2 ART Values at the 1/4T Location for 68 EFPY

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[(a)]	Wt.% Ni[(a)]	CF[(a)] (°F)	1/4T Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF[(b)]	$RT_{NDT}(U)$ [(c)] (°F)	ΔRT_{NDT} [(d)] (°F)	σ_I[(c)] (°F)	σ_Δ [(e)] (°F)	Margin (°F)	1/4T ART[(f)] (°F)
RV Beltline Materials												
Upper Shell Forging 123V303VA1	1.1	0.11	0.72	75.8	0.534	0.825	30	62.5	0.0	17.0	34.0	126.5
Upper to Intermediate Shell Circumferential Weld (Heat # 4275)	1.1	0.35	0.10	160.5	0.534	0.825	0	132.3	20.0	28.0	68.8	201.2
Intermediate Shell Plate C4331-	1.1	0.12	0.60	83.0	4.44	1.378	15	114.4	0.0	17.0	34.0	163.4
Intermediate Shell Plate C4339-2	1.1	0.11	0.54	73.4	4.44	1.378	7.8	101.2	0.0	17.0	34.0	143.0
Using non-credible surveillance data	*2.1*	- - -	- - -	*75.7*	*4.44*	*1.378*	*7.8*	*104.3*	*0.0*	*17.0*	*34.0*	*146.1*
Intermediate Shell Longitudinal Welds L3 and L4 (OD 50%) (Heat # 72445)	1.1	0.22	0.54	167.0	0.796	0.936	-72.5	156.3	12.0	28.0	60.9	144.7
Using credible surveillance data	*2.1*	- - -	- - -	*167.0*	*0.796*	*0.936*	*-72.5*	*156.3*	*12.0*	*28.0*	*60.9*	*144.7*
Intermediate Shell Longitudinal Weld L4 (ID 50%) (Heat # 8T1762)	1.1	0.19	0.57	167.0	0.796	0.936	-48.6	156.3	18.0	28.0	66.6	174.3
Intermediate to Lower Shell Circumferential Weld (Heat # 0227)	1.1	0.187	0.545	147.5	4.45	1.379	0	203.4	0.0	28.0	56.0	259.4
Using credible surveillance data	*2.1*	- - -	- - -	*132.5*	*4.45*	*1.379*	*0*	*182.7*	*0.0*	*14.0*	*28.0*	*210.7*
Lower Shell Plate C4208-2	1.1	0.15	0.55	107.3	4.48	1.380	-30	148.1	0.0	17.0	34.0	152.1
Lower Shell Plate C4339-1	1.1	0.107	0.53	70.8	4.48	1.380	-4.4	97.7	0.0	17.0	34.0	127.3

RV Material	R.G. 1.99, Rev. 2 Position	Wt.% Cu[a]	Wt.% Ni[a]	CF[a] (°F)	1/4T Fluence[b] (x 10^{19} n/cm², E > 1.0 MeV)	1/4T FF[b]	$RT_{NDT}(U)$ [c] (°F)	ΔRT_{NDT} [d] (°F)	σ_I[c] (°F)	σ_Δ [e] (°F)	Margin (°F)	1/4T ART [f] (°F)
Using non-credible surveillance data	*2.1*	*- - -*	*- - -*	*75.7*	*4.48*	*1.380*	*-4.4*	*104.5*	*0.0*	*17.0*	*34.0*	*134.1*
Lower Shell Longitudinal Welds L1 and L2 (Heat # 8T1762)	1.1	0.19	0.57	167.0	0.802	0.938	-48.6	156.7	18.0	28.0	66.6	174.6
RV Extended Beltline Materials												
Inlet Nozzle 1 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.0210	0.177	-4.9	27	19.7	13.5	47.8	69.9
Inlet Nozzle 2 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00484	0.065	-4.9	0.0 (10.0)	19.7	0.0	39.4	34.5
Inlet Nozzle 3 to Upper Shell Weld (Heat # 8T1762)	1.1	0.19	0.57	152.4	0.00660	0.082	-4.9	12.5	19.7	6.3	41.3	48.9
Outlet Nozzle 1 to Upper Shell Weld (Rotterdam)	1.1	0.35	1.0	272.0	0.00491	0.066	30	0.0 (18.0)	0.0	0.0	0.0	30.0
Outlet Nozzle 2 to Upper Shell Weld (Rotterdam)	1.1	0.35	1.0	272.0	0.00361	0.052	30	0.0 (14.3)	0.0	0.0	0.0	30.0
Outlet Nozzle 3 to Upper Shell Weld (Rotterdam)	1.1	0.35	1.0	272.0	0.0156	0.147	30	40.0	0.0	20.0	40.0	110.0

Notes:

(a) Chemical composition values taken from Table 4.2.2-3 and Table 4.2.2-4. Chemistry factor values taken from Table 3-12 of WCAP-18243-NP.

(b) The 1/4T fluence and 1/4T FF were taken from Table 5-2 of WCAP-18343-NP.

(c) Initial RT_{NDT} values and σ_u values are from Table 4.2.2-3 and Table 4.2.2-4.

(d) Per NRC RIS 2014-11, "Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components," embrittlement effects may be neglected for materials with fluence values less than 1 x 10^{17} n/cm^2(E > 1.0 MeV). These materials have fluence values at the clad/base metal interface surface less than 1 x 10^{17} n/cm$^{2;}$ therefore, ΔRT_{NDT} values for these materials are set equal to zero. Calculated ΔRT_{NDT} values are listed in parentheses for information purposes only.

(e) As summarized in Appendix G of WCAP-18243-NP, the surveillance plate data were deemed non-credible, whereas the surveillance data for the weld materials were deemed credible. Per the guidance of Regulatory Guide 1.99 (Revision 2), the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data. Also per Regulatory Guide 1.99 (Revision 2), the weld metal σ_Δ = 28°F for Position 1.1, and with credible surveillance data σ_Δ = 14°F for Position 2.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT}. For welds utilizing initial RT_{NDT} values based on BAW-2308, σ_Δ = 28°F.

(f) ART values calculated in accordance with Regulatory Guide 1.99 (Revision 2) methodology.

Table 4.2.4-9 Summary of the Units 1 and 2 Limiting ART Values Used in the Applicability Evaluation of the Reactor Vessel Heatup and Cooldown Curves

Plant	Limiting Material	1/4T Limiting ART (°F)			3/4T Limiting ART (°F)		
		Existing 48 EFPY Curves Documented in WCAP-14177, Rev. 0[(a)]	TLAA Evaluation at 48 EFPY	TLAA Evaluation at 68 EFPY	Existing 48 EFPY Curves Documented in WCAP-14177, Rev. 0[(a)]	TLAA Evaluation at 48 EFPY	TLAA Evaluation at 68 EFPY
SPS Unit 1	**(Circ Flaw) Circ. Weld:** Intermediate to Lower Shell Circ. Weld, Heat # 72445	228.4	**<u>201.3</u>**	213.9	189.5	158.5	173.6
	(Axial Flaw) Long. Weld: Lower Shell Long. Weld L2 Heat # 299L44 (Position 2.1)		194.3	**<u>219.4</u>**		131.3	153.8
SPS Unit 2	**(Circ Flaw) Circ. Weld:** Intermediate to Lower Shell Circ. Weld, Heat # 0227 (Position 2.1)		199.8	210.7		**<u>166.3</u>**	**<u>179.8</u>**
	(Axial Flaw) Plate: Intermediate Shell Plate C4331-2		156.6[(b)]	163.4[(c)]		135.6	144.0
	Axial Flaw) Weld: Lower Shell Longitudinal Weld L1 and L2 Heat # 8T1762		158.5	174.6		116.2[(d)]	130.7[(e)]

Notes: Limiting values depicted as bold and underlined.

(a) The limiting 48 EFPY 1/4T and 3/4T ART values in the Technical Specifications correspond to the Unit 1 Intermediate to Lower Shell Circumferential Weld (Heat # 72445). The basis for the P-T limit curves is contained in WCAP-14177; however, the applicability was extended to 48 EFPY in a later analysis. See Appendix C of WCAP-18242-NP for details.

(b) Value from Table 6.1-5 of WCAP-18242-NP.

(c) Value from Table 6.1-11 of WCAP-18242-NP.

(d) Value from Table 6.1-6 of WCAP-18242-NP.

(e) Value from Table 6.1-12 of WCAP-18242-NP.

4.2.5 PRESSURE-TEMPERATURE LIMITS

TLAA Description:

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.

The current P-T limits are based upon fluence projections for 60 years of plant operation. Because they were based upon a fluence assumption of 60 years of operation, the P-T limits analyses meet the definition of 10 CFR 54.3(a) (Reference 1.7-2) 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 Part 50, Appendix G, as augmented by ASME Code, Section XI, Appendix G.

The current P-T limits for Units 1 and 2 are based on the K_{Ia} methodology and the latest fluence data through 48 EFPY and are maintained in the Technical Specifications.

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 SLRA 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.

Nozzle materials were evaluated in WCAP-18242-NP at 48 EFPY and 68 EFPY; the nozzle forging materials evaluated are documented in Tables 4.2.4-1, 4.2.4-3, 4.2.2-5, and e. All nozzle materials were assigned the fluence values at the postulated 1/4T flaw location for each specific nozzle in Table 4.2.1-1 and Table 4.2.1-2. Thus, Unit 1 Inlet Nozzle 1 and Unit 2 Inlet Nozzle 1 and Outlet Nozzle 3 have neutron fluence values greater than 1.0×10^{17} n/cm^2 (E > 1.0 MeV) at 68 EFPY. In order to fully assess the Units 1 and 2 P-T limit curves applicability to 68 EFPY, a nozzle corner fracture mechanics analysis was completed for all nozzle materials. These nozzle P-T limit curves were generated and compared to the beltline P-T limit curves to ensure that the beltline curves are bounding. The detailed nozzle forging fracture mechanics evaluation and comparison to the applicable RV beltline P-T limit curves were documented in WCAP-18243-NP. The current beltline curves were confirmed to remain more limiting than the nozzle curves through 68 EFPY.

The development of the current P-T limit curves for normal heatup and cooldown of the primary reactor coolant system for Units 1 and 2 was documented in WCAP-14177. The existing P-T limit curves are based on the K_{Ic} methodology and the limiting beltline material ART values, which are influenced by both the fluence and the initial material properties of that material. The Units 1 and 2 P-T limit curves were developed by calculating ART values utilizing the vessel fluence at the clad/base metal interface corresponding to each RV material. Since the development of the curves, the applicability of the curves has been extended and the fluence values and initial material properties used to calculate ART values have been updated.

The K_{Ic} methodology was used to confirm the applicability of the P-T limit curves developed based on WCAP-14177. The limiting RV material ART values with consideration of the updated 68 EFPY fluence values, revised Position 2.1 chemistry factor values, and updated initial RT_{NDT} values must be shown to be less than or equal to the limiting beltline material ART values used in development of the P-T limit curves contained in WCAP-14177 and the Units 1 and 2 Technical Specifications. The Regulatory Guide 1.99 methodology was used along with the surface fluence of Section 2 of WCAP-18242-NP to calculate ART values for the Units 1 and 2 RV materials at 48 EFPY and 68 EFPY.

Comparisons of the use of the K_{Ic} reference stress intensity factor, instead of the older, more conservative K_{Ia} reference stress intensity factor were conducted to validate that the PT limits for 48 EFPY are conservative for operation through the subsequent period of extended operation. The comparisons of the limiting ART values calculated as part of this RV integrity TLAA evaluation, using updated fluence and initial material properties, to those used in calculation of the existing P-T limit curves are contained in Table 4.2.4-9 for Units 1 and 2. With the consideration of TLAA fluence projections, the applicability of the P-T limit curves in WCAP-14177 may be extended to 68 EFPY for the Units 1 and 2 cylindrical shell materials. Nozzle P-T limit curves were developed per WCAP-18243-NP and compared to the cylindrical shell beltline curves. ART values were generated without the consideration of the methodology in TLR-RES/DE/CIB-2013-01, “Evaluation of the Beltline Region for Nuclear Reactor Pressure Vessels, U.S. NRC Technical Letter Report, Office of Nuclear Regulatory Research [RES]” (Reference 4.8-36). Per WCAP-18243-NP, the applicability of the P-T limit curves may be extended through SLR, because the current Technical Specifications P-T limit curves bound the new P-T limit curves developed in WCAP-18243-NP regardless of the use of the TLR-RES/DE/CIB-2013-01 methodology. Per WCAP-18243-NP, the applicability of the P-T limit curves may be extended through the subsequent period of extended operation.

In addition, the applicable RV flange and closure head initial RT_{NDT} values are bounding and the P-T limit curves flange notch requires no change or further consideration. Finally, the lowest service temperature requirements are not applicable to Units 1 and 2, because the plants are Westinghouse-designed per ASME Code, Section III, and utilize stainless steel reactor coolant system piping.

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 RVs will be adequately managed for the subsequent period of extended operation. The *Reactor Vessel Material Surveillance* program (B2.1.19) and plant Technical Specifications will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the period of applicability for Units 1 and 2.

4.2.6 LOW TEMPERATURE OVERPRESSURE PROTECTION

TLAA Description:

Low temperature overpressure protection (LTOP) system (sometimes referred to as the Reactor Coolant System Overpressure Mitigating System, or the RV Overpressure Mitigating System) at Unit 1 and Unit 2 is required by Technical Specification Limited Condition for Operation 3.1.G. Two pressurizer power operated relief valves (PORV) provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the reactor coolant system pressure from exceeding the P-T limit curves based on 10 CFR 50, Appendix G.

LTOP system setpoints are based on the P-T limits calculation which is a TLAA.

TLAA Evaluation:

The LTOP enabling temperature has been determined for 68 EFPY as discussed in Appendix D of WCAP-18243-NP. Using Code Case N-514, the LTOP enabling temperature is 283°F. The Surry Technical Specification 3.1.G.1.c.(4) specifies an arming temperature of 350°F which is conservative and remains valid for the subsequent period of extended operation.

In WCAP-18242-NP the maximum allowable LTOP system PORV setpoint was calculated to be 399.6 psig for the Units 1 and 2 subsequent period of extended operation. The calculation was performed in accordance with the WCAP-14040-A methodology using LTOP input parameters and the limiting axial flaw steady state ASME Code, Section XI, Appendix G limits calculated for the subsequent period of extended operation at 68 EFPY.

The evaluation showed that the current Technical Specification value of ≤ 390.0 psig is bounding and will remain valid for the subsequent period of extended operation. Since the maximum allowable PORV setpoint was determined using the methodology in WCAP-14040-A, this demonstrates that the current licensing basis PORV setpoint that was developed using K_{Ia} ASME Code, Section XI, Appendix G limits without applying uncertainties was sufficiently conservative.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The LTOP system setpoint and enabling temperature have been projected to the end of the subsequent period of extended operation.

4.3 METAL FATIGUE

Fatigue analyses are required on components designed to ASME Code, Section III, Class 1. Also, certain other codes such as ASME Code, Section III, Class 2 and 3, USAS (ANSI) B31.1, "Power Piping" (Reference 4.8-37), and ASME Section VIII, "Rules for Construction of Pressure Vessels" (Reference 4.8-38), Division 2, may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. NUREG-2192 also provides examples of components likely to have fatigue TLAAs within the current licensing basis 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 current licensing bases for Units 1 and 2. Each of the potential TLAAs were evaluated against the six elements of the TLAA definition specified in 10 CFR 54.3. Those that were identified as fatigue TLAAs are described in WCAP-18341-P (Proprietary), Revision 0, "Resolution of Surry Power Station Units 1 & 2 Time-Limited Aging Analyses for Subsequent License Renewal" (Reference 4.8-39) 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)
- ANSI B31.1 Allowable Stress Analyses (Section 4.3.3)
- Environmentally-Assisted Fatigue (Section 4.3.4)
- Reactor Vessel Internals Fatigue Analyses (Section 4.3.5)

Since initial license renewal, major plant changes have consisted of measurement uncertainty recapture (MUR) power uprate, RV closure head replacement, and 15 inch x 15 inch fuel reload transition. 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. UFSAR Table 4.1-8 and Section 18.4.2 list 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. Current licensing basis fatigue analyses are based upon the original number of design cycles (40 years) and are postulated to bound 60 years of service. Since the fatigue analyses are based upon a number of cycles postulated to bound 60 years of service, these fatigue analyses are considered TLAAs and require disposition for the subsequent period of extended operation (see CN-PAFM-16-55, "Transient Basis for Surry Unit 1 and 2 80 year License Renewal Evaluations" (Reference 4.8-40)).

A review of *Fatigue Monitoring* program (B3.1) data was performed to identify the number of cumulative cycles for each transient type that occurred at Units 1 and 2 up to June 30, 2016. Baseline cycle counts were projected to an 80-year operating life based on the actual accumulation history over the last 10 years (June 30, 2006 - June 30, 2016). They do not represent a revision of the design basis. These transient cycles and projections are documented in Table 4.3.1-1, “80-year Transient Cycle Projections.” Since most nuclear power plants, including SPS Units 1 and 2, have experienced a significant declining trend in accumulation of transients over time, transient projections based on recent operating experience provide an appropriate basis for future projections. Therefore, each monitored design transient was evaluated to determine if the recent 10-year trend had a consistent cycle accumulation rate. The 10-year rate was used to extrapolate the projected number of future occurrences beginning June 30, 2016 and ending at 80 years of plant operation. The end of 80-year life is June 2052 for Unit 1 and March 2053 for Unit 2. As shown in Table 4.3.1-1, the projected cycles for 80 years of plant operation are less than the 40-year design cycles (CLB cycles) used in the fatigue analyses. Therefore, the fatigue analyses for Safety Class 1 components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the Safety Class 1 fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits. A Condition Report will be initiated based upon an administrative limit of 90% of the fatigue cycles.

Regarding the major plant changes that have occurred since initial license renewal; MUR power uprate, RV closure head replacement, and 15 inch x 15 inch fuel reload transition:

- NRC SER for the MUR power uprate indicates, “no additional transients have been proposed as a result of the MUR PU at Surry 1 and 2." (Reference 4.8-41)
- The replacement RV closure heads were installed in 2003 based upon 40-year design cycles.
- No new transients were added as a result of the 15 inch x 15 inch fuel reload transition at Surry Units 1 and 2.

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 period of extended operation.

Table 4.3.1-1 80-Year Transient Cycle Projections

Transients (UFSAR Table 4.1-8 and Section 18.4.2)	Unit 1		Unit 2		CLB cycles (40 year design cycles)
	Accrued Transient Cycles (6/30/16)	80-year Projected Transient Cycles	Accrued Transient Cycles (6/30/16)	80-year Projected Transient Cycles	
Heatup at 100°F/hr	121	165	109	146	200
Cooldown at 100°F/hr	120	164	108	145	200
Loading at 5% of full power per min (1)	Not Monitored	1,589	Not Monitored	1,611	18,300
Unloading of 5% of full power per min (1)	Not Monitored	1,474	Not Monitored	1,512	18,300
Step load increase of 10% full power (but not to exceed full power)(2)	6	7	7	8	2,000
Step load decrease of 10% of full power(2)	7	8	8	9	2,000
Step load reduction from 100% to 50% load (2)	29	30	31	32	200
Reactor trip from full power (3)	132	147	127	142	400
Hydrostatic test pressure, 3,107 psig at 100°F (4)	Not Monitored	5	Not Monitored	5	5
Hydrostatic test pressure, 2,485 psig at 400°F (5)	Not Monitored	40	Not Monitored	40	40
Steady state fluctuations (6)	Not Monitored	Infinite	Not Monitored	Infinite	Infinite
Loss of Load > 15% (2)	0	1	0	1	80
Loss of flow in one loop	15	19	8	20	80
Inadvertent auxiliary pressurizer spray	3	7	3	7	10
Loss of AC power	1	5	1	5	40

Notes: (Reference 4.8-39)

(1) The number of design cycles was based on the assumption of load-follow operation, whereas SPS is operated in the baseload mode. This transient is not monitored. 80-year projected cycles are estimated to be less than approximately 10% of the design cycles. Therefore, it is not necessary to monitor the number of loading and unloading transient cycles. Site procedures administratively limit the ramp rate to less than 2 percent/min. If conditions exist that require a ramp rate of greater than 2 percent/min, the reactor would be tripped. If this were exceeded, it would be entered into the Corrective Action Program. Therefore, no transients of 5 percent/min are expected for remaining plant life and this transient would be redundant to the reactor trip transient.

(2) For this transient, no cycles have occurred over the last 10 years. However, one additional cycle was conservatively included in the 80-year transient cycle projection.

(3) Reactor trips that occur at greater than 25% power are being counted.

(4) Controlled hydrostatic tests have been performed at 3,105 psig at each unit during initial pre-operational testing. No additional hydrostatic tests have been conducted and there are no plans to perform these tests as defined in the CLB in the subsequent period of extended operation. As a result, the 80-year projected cycles for these test transients remain bounded by the CLB.

(5) There are no requirements to perform this test in the subsequent period of extended operation.

(6) Per UFSAR Table 4.1-8, the reactor coolant average temperature for purposes of design are assumed to increase and decrease a maximum of 6°F in 1 minute. The corresponding reactor coolant pressure variation will be less than 100 psig. These pressure and temperature changes are insignificant for fatigue and an infinite number of such fluctuations are assumed to occur.

4.3.2 ASME CODE, SECTION III, CLASS 1 FATIGUE ANALYSES

TLAA Description:

Fatigue analyses are performed per ASME Code, Section III. Each analysis must demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the Code design limit of 1.0 when the component is exposed to all postulated transients.

The following Safety Class 1 components have been assessed for impact on fatigue (Reference 4.8-39):

- Control Rod Drive Mechanism (Section 4.3.2.1)
- Pressurizer (Section 4.3.2.2)
- Reactor Coolant Pump (Section 4.3.2.3)
- Reactor Vessel (Section 4.3.2.4)
- Steam Generators (Section 4.3.2.5)
- Pressurizer Surge Line (Section 4.3.2.6)
- Charging and Accumulator Piping (Section 4.3.2.7)

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. Fatigue waivers are discussed separately in Section 4.3.2.8.

Finally, environmentally-assisted fatigue usage (CUF_{en}), also known as U_{en}, values are identified for bounding locations discussed in Section 4.3.4, Environmentally-Assisted Fatigue.

4.3.2.1 Control Rod Drive Mechanism

TLAA Description:

For Unit 1, the original RV closure head has been replaced with a closure head fabricated by Framatome ANP. However, the Unit 1 CRDMs were harvested from the original RV closure head and reinstalled in the replacement RV closure head. The Unit 1 CRDMs are a Westinghouse L-106A type CRDM design. The fatigue evaluations of the pressure retaining portions of Unit 1 CRDMs were performed to the requirements of the ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The analysis of record (AOR) fatigue CUF results are less than 1.0.

For Unit 2, the replacement RV closure head was fabricated by Mitsubishi Heavy Industries, LTD and Westinghouse performed the design evaluations. The CRDMs, including the rod travel housing, were replaced when the replacement RV closure head was installed. The replacement CRDMs for Unit 2 are a Westinghouse model L-106A full length CRDM. The fatigue evaluations of the pressure retaining portions of the Unit 2 replacement CRDMs were performed to the requirements of the ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The AOR fatigue CUF results are less than 1.0.

TLAA Evaluation:

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue analyses for the CRDM components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the CRDM component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits (Reference 4.8-39).

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.

4.3.2.2 Pressurizer

TLAA Description:

Units 1 and 2 each have a 1,300 ft^3 cylindrical pressurizer with cast upper and lower heads. The fatigue evaluations of the pressurizer were performed to the requirements of ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs.

Pressurizer surge line thermal stratification was identified in NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification” (Reference 4.8-42) and is discussed in Section 4.3.2.6, Pressurizer Surge Line. Westinghouse has identified insurge/outsurge events, which imposed thermal loads not considered in the original design analyses and the evaluation of the surge lines is discussed in Section 4.3.4.

TLAA Evaluation:

The power uprate resulted in two areas of consideration. The general structural evaluation used power uprate loads and had no impact to the transient design cycle counts. Also evaluated in WCAP-15607-P, “Evaluation of Pressurizer Insurge/Outsurge Transients for Surry Subsequent License Renewal – Environmental Assisted Fatigue,” (Reference 4.8-43) was the impact of the revised NSSS operating parameters on the pressurizer insurge/outsurge transients, and their effect, in turn, on the integrity of the lower head and surge nozzle regions. The AOR fatigue CUF results are less than 1.0 (Reference 4.8-39).

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue analyses for the pressurizer components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the pressurizer component fatigue analyses, the Fatigue Monitoring (B3.1) program will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits (Reference 4.8-39).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the pressurizer components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.3 Reactor Coolant Pump

TLAA Description:

The reactor coolant pumps are Westinghouse Model 93A. The reactor coolant pumps were not designed to ASME Code, Section III. However, fatigue evaluations of the Reactor Coolant Pumps were performed to various editions of the ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs (Reference 4.8-39).

TLAA Evaluation:

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue analysis for the reactor coolant pump components remains valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the reactor coolant pump fatigue analysis, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits (Reference 4.8-39).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the reactor coolant pump components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.4 Reactor Vessel

TLAA Description:

The RV fatigue evaluations were performed to the requirements of ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs (Reference 4.8-39).

TLAA Evaluation:

Units 1 and 2 RV heads were replaced during refueling outages conducted in the year 2003. The replacement RV heads have penetrations and connecting welds fabricated using nickel alloy materials more resistant to primary water stress corrosion cracking than the Alloy 600 material used in the fabrication of the original heads.

For Unit 1, the original closure head has been replaced with a closure head fabricated by Framatome ANP for a French utility power plant, but was purchased by Dominion. The original Unit 1 RV closure head was replaced with a closure head fabricated and manufactured in accordance with the French Construction Code (RCC-M), “Design and Construction Rules for the Mechanical Components of PWR Nuclear Islands” (Reference 4.8-44). The sizing calculations and the stress and fatigue analysis were performed to ASME Code, Section III, 1995 Edition with Addenda through 1996. The Design Report certified that the closure head meets the design requirements and stress limits for ASME Code, Section III, 1995 Edition with Addenda through 1996. Additional details are provided in UFSAR Section 4.1-6. The AOR fatigue CUF results are less than 1.0.

For Unit 2, the replacement RV closure head was fabricated by Mitsubishi Heavy Industries, LTD and Westinghouse performed the design evaluations. The replacement head was evaluated to the requirements of the ASME Code, Section III 1995 Edition with Addenda through 1996. The AOR fatigue CUF results are less than 1.0.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue analyses for the RV components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the RV component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits (Reference 4.8-39).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the RV components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.5 Steam Generators

TLAA Description:

The steam generators consist of both original and replacement components. The steam generator transition cone just below the upper shell was cut and the lower portion was removed, and replaced with a replacement steam generator in 1981 for Unit 1 and in 1980 for Unit 2. The upper shell with its steam separation equipment was retained and welded to the lower replacement portion. The result is a unit consisting of a lower shell and tube bundle of a Westinghouse Model 51F steam generator, and the modified feedwater and steam separation equipment of the original 51 Series steam generator. All steam generator components, both original and replacement, were evaluated to the Model 51F loading conditions. The shell side of the steam generator conforms to the requirements for Class A vessels and is so stamped as permitted under the rules of ASME Code, Section III. The fatigue evaluations of the steam generator were performed to the requirements of ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. AOR fatigue CUF results are less than 1.0 (Reference 4.8-39).

TLAA Evaluation:

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue analyses for the steam generator components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the steam generator component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits (Reference 4.8-39).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the steam generator components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.6 Pressurizer Surge Line

TLAA Description:

NRC Bulletin 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 stratification effects. The demonstration was an ASME Code, Section III fatigue analysis to account for thermal stratification. The analysis uses time-limited assumptions such as thermal and pressure transients and operating cycles for the licensed life of the plant. Therefore, the analyses required by NRC Bulletin 88-11 met the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation:

The original analyses performed to demonstrate compliance with design requirements considered ASME Code requirements and utilized the design set of NSSS transients. 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 surge line is identified as a fatigue sentinel location and is described in Section 4.3.4. When considering EAF, Dominion elected to utilize ASME Code, Section XI, Appendix L instead of conducting fatigue analysis under ASME Code, Section III, NB-3200. In response to NRC Bulletin 88-11, the ASME Code stress limits and cumulative usage factor requirements were shown to be acceptable for the current licensed life.

For initial license renewal, pressurizer surge line thermal stratification was managed under 10 CFR 54.21.(c)(1)(iii) under the ISI program. Recently, in NRC Letter to Stoddard “Surry Power Station, Units 1 and 2 - Revised License Renewal Commitment Pressurizer surge Line Inspection Frequency,” (Reference 4.8-45), the NRC authorized re-inspection, per ASME Code, Section XI, Appendix L, once every ten years.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The *Fatigue Monitoring* program (B3.1) will monitor the transient cycles and severities which are the inputs to these analyses and require action prior to exceeding design limits that would invalidate their conclusions. For subsequent license renewal, the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) will manage the pressurizer surge line thermal stratification through inspection every ten years based upon the ASME Code, Section XI, Appendix L methodology approved by the NRC.

4.3.2.7 Charging and Accumulator Piping

TLAA Description:

Piping systems designed in accordance with ANSI B31.1 are not required to perform an implicit analysis of cumulative fatigue usage. However, during initial license renewal, as a NRC commitment, Surry had detailed fatigue calculations (see References 4.8-58 and 4.8-59) including reactor water environmental effects on fatigue performed for the charging and accumulator cold leg nozzles; both of which were previously identified in NUREG/CR-6260 as sentinel locations for initial license renewal.

TLAA Evaluation:

For initial license renewal, detailed stress and fatigue evaluations were performed according to the methods of the ASME Code, Section III. The AOR fatigue CUF results are less than 1.0.

Although not required since the CUF is less than unity, Dominion has elected to manage the effects of fatigue for these locations on a sampling basis with the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) during the subsequent period of extended operations.

When considering these previously-identified NUREG/CR-6260 locations, Dominion elected to utilize ASME Code, Section XI, Appendix L. Flaw tolerance evaluations were conducted for these locations per the guidance of ASME Code, Section XI, Nonmandatory Appendix L. For the charging and accumulator cold leg nozzles, the transients used to simulate growth of the postulated flaws in the Appendix L evaluations used 10 years of projected cycles. Following re-inspection the cycle counts used in the Appendix L evaluation are set to zero when no flaw is disclosed for each new inspection interval. The fatigue sensitive transients used in the Appendix L evaluation are tracked in the *Fatigue Monitoring* program (B3.1). The Corrective Action Program tracks branch line specific activities such as safety injection and accumulator injection events.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended functions of the charging and accumulator piping will be managed by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) through the subsequent period of extended operation.

4.3.2.8 ASME Code, Section III, Class 1 Component Fatigue Waivers

TLAA Description:

A detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements of ASME Code, Section III. Fatigue waivers that consider transient cycles that occur over the life of the plant constitute TLAAs. ASME Code, Class 1 component fatigue waivers are discussed in this section.

The following equipment have sub-components that conform to the waiver of fatigue requirements in ASME Code, Section III.

- Unit 1 Control Rod Drive Mechanisms
  - Upper Joint - Cap
  - Upper Joint - Rod Travel Housing
- Reactor Coolant Pumps
  - Casing

- Main Flange
- Seal Housing
- Ring Clamp
- Ring Clamp Bolts
- Casing Feet
- No. 1, 2, & 3 Seal Leakoff Nozzle
- No. 1 Seal Bypass Nozzle
- No. 3 Seal Injection Nozzle
- Weir Plate

- Steam Generators
  - Welded Diaphragms
  - Tube Plugs (mechanical and welded)

TLAA Evaluation:

To address the metal fatigue TLAAs identified as part of SLR, the CLB fatigue waivers for the ASME Code, Section III, Class 1 components were determined by reviewing the TLAA identification work performed for initial license renewal and updating it to incorporate any fatigue-related work that has been performed to-date.

The transients associated with each evaluation were consolidated into an overall transient set applicable to the fatigue waivers identified above. In order to document that the CLB fatigue waivers remain valid and bounding through the subsequent period of operation, transient cycle projections for 80 years of operation were compared against the CLB cycles for each transient. As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue waivers for Class 1 components remain valid for the subsequent period of extended operation (Reference 4.8-39). In order to ensure the design cycles remain bounding in the ASME Code, Section III Class 1 component fatigue waivers, the *Fatigue Monitoring* program (B3.1) will track cycles for significant transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The ASME Code, Section III, Class 1 component fatigue waivers will be managed by the *Fatigue Monitoring* program (B3.1) through the subsequent period of extended operation. The *Fatigue Monitoring* program (B3.1) will monitor the transient cycles and severities which are the inputs to the fatigue waiver analyses and require action prior to exceeding design limits that would invalidate their conclusions.

4.3.3 ANSI B31.1 ALLOWABLE STRESS ANALYSES

TLAA Description:

The reactor coolant system's primary loop piping and the balance-of-plant piping in scope for subsequent license renewal are analyzed to the requirements of ANSI B31.1, Power Piping. There are two aspects of note that pertain to fatigue for the ANSI B31.1 piping. The first aspect is discussed below and is related to the design of the piping which does not utilize fatigue usage factors. The second aspect deals with the concern of environmental effect which is discussed in Section 4.3.4.

For piping systems designed in accordance with ANSI B31.1, 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 ANSI B31.1, 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:

ANSI B31.1 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 piping systems designed in accordance with ANSI B31.1 requirements 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 generator nitrogen, main steam, blowdown, feedwater, condensate, chemical and volume control, extraction steam, residual heat removal, steam drains, 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. For example, the residual heat removal system cycles twice per shutdown/startup and therefore, has fewer cycles than the residual heat removal system piping at the boundary with the reactor coolant system. 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 systems, designed in accordance with ANSI B31.1 requirements, are affected by thermal and pressure transients that are different than the reactor coolant and power cycles discussed above: auxiliary steam, boron recovery, Containment vacuum and leakage monitoring, emergency diesel generator (engine exhaust), alternate AC diesel generator (engine exhaust), security diesel (engine exhaust), fire protection (fire pump diesel exhaust), heating steam, recirculation spray, sampling system, and service water. 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 provides 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 ANSI B31.1 allowable stress analyses remain valid for the subsequent period of extended operation.

Initial license renewal validated that the ANSI B31.1 piping would receive less than 7,000 cycles. For SLR, it is confirmed that the ANSI B31.1 piping is projected to receive less than 7,000 cycles.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The ANSI B31.1 allowable stress analyses remain valid for the subsequent period of extended operation.

Table 4.3.3-1 80 Year Transient Cycle Projections for ANSI B31.1 Piping

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Auxiliary Steam	Stripper feed heat exchanger kept in warm steady state condition. Assume 50 to 75 cycles per year.	Less than 7,000 cycles
Blowdown	Continuous blowdown during power operations. RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Boron Recovery	Stripper feed heat exchanger kept in warm steady state condition by Auxiliary Steam. Assume 50 to 75 cycles per year (80 years x 75 cycles/year = 6,000 cycles).	Less than 7,000 cycles
Chemical and Volume Control	Normal Charging and Letdown during the RCS power operation at steady state temperature. Conservatively assume 2 cycles per year.	Less than 1,000 cycles
Condensate	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Containment Vacuum and Leakage Monitoring	Auxiliary Steam to the Containment Vacuum Ejectors used from cold shutdown to intermediate shutdown – once per 18 months plus margin = 100 cycles.	Less than 1,000 cycles
Emergency Diesel Generator (Exhaust)	One start per month plus transients and pre-operational testing.	Less than 2,000 cycles
Alternate AC Diesel Generator (Exhaust)	One start per quarter for testing equal 320 cycles.	Less than 1,000 cycles
Security Diesel Generator (Exhaust)	One start per month – 960 cycles.	Less than 2,000 cycles
Extraction Steam	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Feedwater	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Fire Protection	Fire pump diesel engine exhaust cycles only during pump testing every 31 days. (12 cycles/year x 80 years = 960 cycles).	Less than 2,000 cycles
Generator Nitrogen	Piping connected to Steam Generators exposed to similar cycles as RCS from Table 4.3.1-1.	Less than 7,000 cycles
Heating Steam	Cycles based on seasonal heating. Conservatively assume 85 cycles per year (80 years x 85/year = 6,800 cycles).	Less than 7,000 cycles
Main Steam	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Reactor Coolant	RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Recirculation Spray	Thermal cycle during design basis accident only (transient).	Less than 7,000 cycles
Residual Heat Removal	System piping heated during shutdowns and startups. 2 per heatup and cooldown each refueling cycle.	Less than 2,000 cycles

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Safety Injection	Connection to RCS subject to power cycle transients from Table 4.3.1-1. Pump testing below temperature of concern for thermal fatigue.	Less than 7,000 cycles
Sampling System	Hot and Cold Leg Samples: Once per week except during outages (52 weeks x 80 years - 4,160 cycles	Less than 5,000 cycles
	Residual Heat Removal Samples: Twice per week during heat up and cool down. As shown in Table 4.3.1-1, 80-year projected cycles for heatup and cooldown - 329 for Unit 1 and 291 for Unit 2 are less than 400.	Less than 1,000 cycles
	Pressurizer Liquid Samples: Less than 40 cycles per year (80 years x 40 = 3,200 cycles)	Less than 4,000 cycles
Service Water	Emergency Service Water Pump Diesel Exhaust - one start per month = 960 cycles (80 years x 12 months/year = 960 cycles).	Less than 2,000 cycles
Steam Drains	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles

4.3.4 ENVIRONMENTALLY-ASSISTED FATIGUE

TLAA Description:

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on cumulative usage factor (CUF) must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components” (Reference 4.8-46) and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. These additional limiting locations are identified through an environmental fatigue screening evaluation. The environmentally assisted fatigue (EAF) screening process consisted of two methods. The first method made use of existing fatigue usage values for the ASME Code, Section III components. The second method consisted of the EPRI common basis stress evaluation (CBSE) method for estimating fatigue usage for the ANSI B31.1 piping without fatigue values per EPRI Report 1024995, “Environmentally Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations” (Reference 4.8-47). The EAF screening evaluation reviewed the CLB fatigue evaluations for all ASME Code, Section III reactor coolant pressure boundary components and ANSI B31.1 piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

TLAA Evaluation:

To support subsequent license renewal, calculations were prepared to document the evaluations of environmentally-assisted fatigue for ASME Code, Section III pressure boundary components and piping that contact the reactor coolant, and determine fatigue-sensitive locations for comparison and ranking. These evaluations are for subsequent license renewal purposes and do not amend the existing design reports. The TLAA evaluation is presented separately for ASME Code, Section III and ANSI B31.1 components and piping. Discussion of the screening approaches used for the ASME Code, Section III Components and ANSI B31.1 piping are provided below due to slight differences in the screening approach used. As a result of the EAF screening evaluation, there were other locations found that could potentially be more limiting than the NUREG/CR-6260 locations (see WCAP-18341-P, SIA 1600274.305, Revision 2, “Selection of Sentinel Locations Based on Environmentally Assisted Fatigue Screening” (Reference 4.8-48) and SIA FP-SPS-401, Revision 1, “Surry Subsequent License Renewal Fatigue Management Accumulation Report,” (Reference 4.8-49). 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.

ASME Code, Section III Components

In the EAF screening process for ASME Code, Section III components with existing fatigue usage values, all of the applicable ASME Code, Section III components that are susceptible to EAF were reviewed and categorized into common systems, or transient sections. Screening F_{en} factors were developed for each component so that CUF_{en} can be calculated and compared. The methodology outlined in NUREG/CR-6909, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report" (Reference 4.8-50) is used for stainless steels, carbon and low-alloys steels, and Ni-Cr-Fe alloys. However, the prepublication version of Revision 1 (Reference 4.8-51) was available. Since draft Revision 1 (Reference 4.8-52) had not been finalized at the time screening was performed, the most limiting of the two versions was conservatively considered in this EAF evaluation. Following screening, NUREG/CR-6909, Revision 1 was issued as final. Based on the derivation of the screening F_{en} values, NUREG/CR-6909, Revision 0 is limiting for Stainless Steel and Ni-Cr-Fe alloy materials while NUREG/CR-6909, draft Revision 1 (References 4.8-50 and 4.8-52) is limiting for Carbon and Low-Alloy steels. Revision 1 of NUREG/CR-6909 has been reviewed. The review confirms that the screening results based upon Revision 0 of NUREG/CR-6909 and draft Revision 1 of NUREG/CR-6909 are bounding relative to Revision 1 of NUREG/CR-6909.

Conservative values are chosen for each of the F_{en} input parameters: sulfur content, service temperature, strain rate, and dissolved oxygen (DO). EPRI Technical Report, "Pressurized Water Reactor Primary Water Chemistry Guidelines" (Reference 4.8-53) is followed. Therefore, the F_{en} calculation considers a value of 0.005 ppm for the dissolved oxygen (DO) content when the system temperatures are elevated, which is the action level 1 value for PWR environmental conditions under normal operation. DO is sampled in the reactor coolant system 5 times per week and runs less than 0.005 ppm.

For the periods during heatup/cooldown operations when DO may be elevated, pressurizer temperature is ≤ 250°F (121°C). During these times, the system ΔT between the pressurizer and RCS is low (≤ 80°F), and pressurizer I/O transient events with this magnitude of system ΔT are not significant contributors to fatigue. For pressurizer temperatures above 250°F, Hydrazine addition is used to control dissolved oxygen. For cooldowns, H_2 concentration in the RCS is used to minimize dissolved oxygen in the RCS through the pressurizer steam bubble collapse. Furthermore, fluid temperatures during the elevated DO times are in the range where T* values are the lowest. Using the formulas presented in NUREG/CR-6909, Revision 0 for stainless steels, the second term in the applicable F_{en} equation exponent reduces to zero when the temperature is below 150°C which negates the influence of DO at low temperatures. In the formulas presented in NUREG/CR-6909, draft Revision 1 for Carbon and Low-Alloy steels, the relationship for T* is linear while O* is logarithmic, which implies the increase in O* may be offset by the decrease in T*. Therefore, the use of 0.005 ppm for DO content is acceptable for the F_{en} evaluations (Reference 4.8-39).

For the systems where the NUREG/CR-6260 locations have the highest screening CUF_{en} no additional locations were considered for EAF. For those systems where the NUREG/CR-6260 locations do not have the highest screening CUF_{en} or a NUREG/CR-6260 location does not exist, the locations within that system that have the highest screening CUF_{en} are the sentinel locations. The final set of sentinel locations are meant to supplement those identified in NUREG/CR-6260, resulting in a comprehensive list of plant-specific primary equipment 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. Other locations were also excluded during this step and included locations not in contact with primary coolant, locations excluded from fatigue usage factor calculation based on fatigue waivers and locations with a CUF of 0.0.

Sentinel locations for ASME Code, Section III components were identified as follows:

- Components with a screening CUF_{en} of less than unity were removed.
- Stress basis analysis ranking, which is a consistent ranking approach to assess the level of technical rigor and qualification criteria for each component within the thermal zone, was assessed for each remaining component.
- Locations with the maximum screening CUF_{en} in each thermal zone, for each applicable material type, were retained.
- Comparison of components of different thermal zones within common systems/equipment was performed.
- Comparison of candidate-sentinel locations against any NUREG/CR-6260 locations within the system was completed. Components with a CUF_{en} less than the NUREG/CR-6260 location were removed from the final set of sentinel locations.

The results of the EAF calculations for the sentinel locations are summarized in Table 4.3.4-1. In addition to the CUF_{en} values, the original analysis of record (AOR) CUF, the reduced CUF developed for SLR, and a brief summary of the conservatisms removed from the AOR for ASME Code, Section III components are also provided in Table 4.3.4-1.

ANSI B31.1 Piping

The majority of ANSI B31.1 piping locations does not have fatigue usage calculations. Accordingly, the EPRI CBSE methodology was used to produce estimated fatigue usage.

Fatigue cumulative usage factors (CUF) were not generated in response to NRC IE Bulletin 88-08 (IEB 88-08), Supplement 2, “Thermal Stresses in Piping Connected to Reactor Coolant System” (Reference 4.8-54). Ultrasonic inspections were performed in response to IEB 88-08.

Over the operating history of Units 1 and 2, CUFs at several of the ANSI B31.1 piping locations have been calculated to the requirements of ASME Code, Section III.

- The pressurizer surge lines have been analyzed to the requirements of ASME Code, Section III, Class I, 1986 with addenda through 1987 in response to NRC Bulletin 88-11
- The charging nozzles have been analyzed to the requirements of ASME Code, Section III, Class I, 1989 for initial license renewal
- The accumulator nozzles have been analyzed to the requirements of ASME Code, Section III, Class I, 1989 for initial license renewal

CUF values were generated in response to NRC Bulletin 88-11. For the initial license renewal period of extended operation, the ISI Program managed the effects of fatigue on the pressurizer surge line through inservice periodic inspections. The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) will continue to manage the effects of fatigue on the pressurizer surge line during the subsequent period of extended operation. A flaw tolerance evaluation is used to establish the inspection frequency.

In response to NRC questions for initial license renewal, CUF values adjusted for environmental effects were established for the charging nozzle and accumulator nozzles. The CUF values adjusted for environmental effects were less than unity.

Not enough information exists to complete a screening evaluation using CUF values to determine which ANSI B31.1 locations are the most fatigue sensitive. Therefore, the EPRI CBSE process (Reference 4.8-47) uses a simplified version of Class 1 piping analysis rules where thermal transient stresses are estimated using closed form solutions, and other stresses are calculated based on existing piping equations. The advantage of the EPRI CBSE process is that the same formulas and level of detail are used to calculate stress range and estimated fatigue usage so that results at different points can be compared. The results of the EPRI CBSE screening process confirmed the existing NUREG-6260 locations and identified two new fatigue sensitive locations, one in the residual heat removal system and the other on the pressurizer spray line, for further evaluation to assess the impact of environmentally assisted fatigue (EAF). The CBSE process is not applied to the ANSI B31.1 piping, listed above, with existing CUF values.

The initial set of candidate locations includes the locations for which the estimated fatigue usage was determined. To reduce the size of the initial set, a location is eliminated if CUF_{en} (U_{en} in the EPRI report) is less than 0.8, the example screening limit provided in the EPRI EAF screening report. In addition, all locations that are not part of the reactor coolant pressure boundary are removed at this stage. NUREG/CR-6260 locations were not screened out and were conservatively retained (Reference 4.8-47).

F_{en} from NUREG/CR-6909 draft Revision 1 has been used for screening to address the effect of the reactor coolant environment for each location. F_{en} values are calculated based on material type, and conservative values are chosen for input parameters. To reduce excess conservatism for stainless steel locations, strain rate is estimated for input to the calculation of F_{en}. The F_{en} value used in the evaluation is the average of the maximum F_{en} value for the material and the F_{en} based on the assumed strain rate. Although NUREG/CR-6909 draft Revision 1 screening calculations used equations that are unchanged between the draft revision and current pre-publication version of Revision 1, the final Revision 1 version however did change the maximum strain rate changed from 10% to 7%. This does not affect the screening calculations, since for CBSE a maximum strain rate value of 5% is used.

EPRI primary water chemistry guidelines are followed. Therefore, the F_{en} calculation considers a value of 0.005 ppm for the DO content, which is the action level 1 value for PWR environmental conditions under normal operation. DO is sampled in the reactor coolant system 5 times per week and runs less than 0.005 ppm.

The screening process for piping that undergoes essentially the same thermal and pressure transients during plant operations involves grouping into different thermal zones identified in Table 4.3.4-1.

Within each material type in a thermal zone, the location with the highest estimated or maximum CUF_{en} is selected during initial screening; the location with the second highest CUF_{en} is also selected if the second highest CUF_{en} value is greater than 50% of the highest. If the third-highest CUF_{en} value is greater than 25% of the highest CUF_{en} value within a thermal zone, then the top three locations in that thermal zone are selected.

For the ANSI B31.1 piping that screens in, the following rules in the EPRI screening process were considered to identify bounding sentinel locations across thermal zones:

- One thermal zone can bound another thermal zone in a system if the CUF and F_{en} values for one sentinel location in one thermal zone are each higher than those for the sentinel locations in other thermal zones, and the CUF_{en} value is more than twice those in the other zones.
- One material in a thermal zone can bound other materials in the same thermal zone if the CUF and F_{en} values for one sentinel location composed of one material are each higher than the CUF and Fen values for the sentinel locations composed of all other materials, and the CUF_{en} is more than twice those for the other materials.
- One material in a thermal zone can bound other materials in another thermal zone if both of the preceding two criteria are true.

The impact of applying the above thermal zone rules to reduce the number of locations was to identify the charging nozzle as the bounding location with respect to the balance of the other charging line locations and to identify the hot leg surge nozzle as the bounding location with respect to the hot leg and cold leg reactor coolant loop piping.

Sentinel Locations

Sentinel locations are those locations chosen for more detailed analysis, monitoring, inspection, or replacement. These locations are chosen to have bounding CUF_{en} values compared with other locations.

The results of the EAF calculations for the ASME Code, Section III components and ANSI B31.1 reactor coolant pressure boundary piping (greater than one inch diameter) out to the second isolation valve are summarized in Table 4.3.4-1.

Fatigue Management

For ASME Code, Section III components with CUF_{en} greater than 1.0, ASME Code, Section III, NB-3200 calculations were prepared to remove conservatisms used in the analysis of record, thereby reducing the CUF_{en} to less than 1.0. The effects of fatigue on the intended functions of these ASME Code, Section III components will be managed by the *Fatigue Monitoring* program (B3.1) through the use of cycle counting. This approach was applied to the following components:

- CRDM head adapter - J-groove weld
- CRDM upper latch housing
- RV outlet nozzles and support pads
- CRDM upper joint canopy weld
- Pressurizer spray nozzle
- Pressurizer surge nozzle to safe end weld
- Pressurizer lower head at heater penetration

For sentinel piping locations, the effects of fatigue will be managed by application of the In-service Inspection program (*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)) during the subsequent period of operation based on results of flaw tolerance evaluation conducted per the guidance of ASME Code, Section XI, Nonmandatory, Appendix L. 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 evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location. For a postulated initial flaw, crack growth is simulated until the flaw has reached the allowable flaw depth or the end of the subsequent period of extended operation, whichever comes first.

The purpose of the flaw tolerance evaluation is to establish an appropriate inspection frequency that is consistent with the typical 10-year in-service inspection program for the auxiliary piping systems. The input used from each of the auxiliary piping systems (geometry, transient cycles and definitions, material properties, piping loads, etc.) bound both Units 1 and 2. The ASME Code, Section XI, Appendix L flaw tolerance evaluation consists of postulating a hypothetical inside surface axial and circumferential flaw. There are six sentinel locations analyzed using ASME Code, Section XI, Appendix L presented in Table 4.3.4-1. Two approaches were taken to analyze the sentinel locations. The first approach is for the pressurizer surge line. The second approach is for the remaining five branch line piping locations.

The pressurizer surge line ASME Code, Section XI, Appendix L evaluation used transients to simulate growth of the postulated flaws prorated over ten years of operation. Transients used in the pressurizer surge line ASME Code, Section XI, Appendix L evaluation are tracked by the *Fatigue Monitoring* program. In NRC letter to Stoddard dated June 29, 2018, “Surry Power Station, Units 1 and 2 - Revised License Renewal Commitment Pressurizer surge Line Inspection Frequency,” the NRC approved a request for a ten-year inspection interval for the surge lines in Units 1 and 2 for the initial license renewal.

For the branch line piping, the transients used to simulate growth of the postulated flaws in the ASME Code, Section XI, Appendix L evaluations used ten years of projected cycles. The ASME Code, Section XI, Appendix L evaluations used ten years of projected cycles and the branch line piping will be inspected on a ten-year inspection frequency. The combined selection of transients and inspection frequency is very conservative, thereby ensuring the inspection frequencies remain adequate. 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 reactor coolant loop piping. The second group of transients is transients associated with branch line piping. The transients for the reactor coolant piping are a subset of transients applicable to the ASME Code, Section III components. The fatigue monitoring program tracks significant transient cycles for the ASME Code, Section III components. The site also tracks insurge and outsurge cycles pertaining to the surge line.

Following re-inspection the cycle counts used in the ASME Code, Section XI, Appendix L evaluation are set to zero when no flaw is disclosed for each new inspection interval.

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, 2004 Edition which is the current code of record. In addition, it was confirmed that use of a fixed aspect ratio of six (6) produces the same time between inspections as the equivalent single crack aspect ratio provisions of ASME Code, Section XI, Appendix L, 2013 Edition. Based on previous inspection records, there are no detected indications at these auxiliary piping systems; therefore, the methodology of ASME Code, Section XI, Appendix L can be used. As per ASME Code, Section XI, Appendix L, a postulated initial flaw size larger than the ASME Code, Section XI acceptance standards in Table IWB-3514-2 (with aspect ratio of 6) was used in the fatigue crack growth (FCG) analysis. The piping systems evaluated here are constructed from stainless steel material, where the only significant crack growth mechanism of consideration is fatigue crack growth.

Based on the fatigue crack growth evaluation, the allowable operating period was determined as the length of time it takes for the postulated initial flaw size to grow to the maximum allowable end-of-evaluation period flaw size. The fatigue crack growth analysis was 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 4.8-55). The results of the ASME Code, Section XI, Appendix L evaluations are provided in Table 4.3.4-2. See WCAP-18339-P, “Surry Units 1 and 2 ASME Section XI Appendix L Flaw Tolerance Evaluation for Safety Injection, Residual Heat Removal, Pressurizer Spray, Charging and Accumulator Lines” (Reference 4.8-56) and SIA Report Number 1601007.401, “Flaw Tolerance Evaluation of the Surry Unit 1 and 2 Hot Leg Surge Line Nozzles Using ASME Code Section XI, Appendix L” (Reference 4.8-57).

In-service inspections of the ASME Code, Section XI, Appendix L piping will be performed every ten years. Each weld in the inspection population will be ultrasonically inspected once prior to establishing the 7th and 8th Inspection Interval schedule for Units 1 and 2 ASME Code, Section XI, Appendix L locations. Going forward after the first ultrasonic inspection, one weld in each of the six groups will be ultrasonically inspected every 10 years: Surge Line, Accumulator, Charging, Residual Heat Removal, Pressurizer Spray, and Safety Injection. The ASME Code, Section XI, Appendix L inspections will be conducted by the In-service Inspection (*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)) program. The ASME Code, Section XI, Appendix L inspections are identified in Table 4.3.4-3 for Unit 1 and in Table 4.3.4-4 for Unit 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended functions of ASME Code, Section III components and B31.1 piping that contact reactor coolant will be managed by the *Fatigue Monitoring* program (B3.1), the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) and the *Steam Generators* program (B2.1.10) through the subsequent period of extended operation.

Table 4.3.4-1 Sentinel Locations

System / Thermal Zone	Location	Material	AOR CUF	SLR CUF	F_{en}(1)	U_{en}(11)	Analysis Method	Fatigue Management Method
RC/ RC transients only	CRDM head adapters (J-groove weld) - replacement RV closure heads (18)	Ni-CR-Fe Alloy	0.964	0.097	4.524	0.439	The analysis of record reported a CUF from a non-wetted outside surface. The CUF of 0.097 represents the wetted inside surface	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	RV outlet nozzles and support pads(6)(7)	LAS	0.256	0.133 (6)	6.276	0.835	The analysis of record reported a CUF from a non-wetted outside surface. The CUF of 0.133 represents the wetted inside surface	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	RV inlet nozzles(7)	LAS	0.007	0.007	6.276	0.045	Bounded by outlet nozzle	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	RV bottom head-to-shell juncture(7)	LAS	0.0016	0.0016	6.276	0.010	Bounded by outlet nozzle	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	CRDM upper latch housing and rod travel housing – upper latch housing(3)(5) (14)	SS	0.300	0.088	11.27	0.995	NB-3200 (Prorated the number of heat-up and cool-down cycles to account for the operational life of the replacement component and reduced the number of zero stress states assumed in the analysis.)	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	CRDM upper joint – Canopy (2) (14)	SS	0.858	0.088	8.000	0.703	NB-3200 (Reduced the number of zero stress states assumed in the analysis and refined the control rod drop transient stresses.)	*Fatigue Monitoring* program (B3.1)-Cycle Counting

Table 4.3.4-1 Sentinel Locations

System / Thermal Zone	Location	Material	AOR CUF	SLR CUF	F_{en}[1]	U_{en}[11]	Analysis Method	Fatigue Management Method
PZR upper head/shell [10]	Pressurizer spray nozzle[14]	SS	0.848	0.473	2.08	0.984	NB-3200 (Spray transient refined by incorporating plant specific data and operational trends.)	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	Pressurizer spray nozzle – Piping[12]	SS	N/A	6.953	1.53	10.64	Appendix L	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)
	Upper shell	LAS	0.416	0.158	6.276	0.994	NB-3200 (Reduced the number of spray transients and implemented the low-alloy fatigue curve (NUREG/CR-6909. Rev. 1 Draft))	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	Safety and Relief nozzles	CS	0.151	0.151	6.276	0.948	No conservatism removed.	*Fatigue Monitoring* program (B3.1)-Cycle Counting
RC/PZR lower head [10]	Pressurizer lower head at heater penetration	CS	0.820	0.084	6.276	0.528	NB-3200 (I/O transient event distribution was refined by incorporating plant specific data and operational trends.)	*Fatigue Monitoring* program (B3.1)-Cycle Counting
	Hot leg surge nozzle - bounding location[7]	SS	0.8608[19]	0.713	2.73	1.95	Appendix L[16]	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)
	Pressurizer surge piping	SS	0.6709[19]	1.133	7.66	8.69		
	Pressurizer surge nozzle to safe end weld[14]	SS	0.450	0.093	10.41	0.965	NB-3200 (I/O transient event distribution was refined by incorporating plant specific data and operational trends.)	*Fatigue Monitoring* program (B3.1)-Cycle Counting
CVC/ Charging near CL	Charging nozzle[7][15]	SS	0.0867	0.0867	3.858[17]	0.3343	Appendix L	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)

Table 4.3.4-1 Sentinel Locations

System / Thermal Zone	Location	Material	AOR CUF	SLR CUF	F_{en}(1)	U_{en}(11)	Analysis Method	Fatigue Management Method
SI/6" SI near cold leg	Safety injection nozzle(7)(12)	SS	N/A	0.138	2.41	0.332	Appendix L	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)
RHR/14" RHR away from HL	Residual heat removal piping – limiting location (7)(12)	SS	N/A	0.128	1.65	0.211	Appendix L	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)
Steam generator primary side components	Tubes (4)	Ni-CR-Fe Alloy	0.764	N/A	N/A	N/A	N/A	*Steam Generators* program (B2.1.10)
Accumulator	Accumulator piping(7)(13)	SS	0.0982	0.0982	4.28(17)	0.42	Appendix L	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)

Notes:

1. The F_{en} factor documented in this table accounts for the environmental effects on metal exposed to primary side water chemistry.
2. Applicable to Unit 1 only.
3. Applicable to Unit 2 only.
4. This sentinel location is addressed through the Steam Generators Aging Management (B2.1.10) program. The steam generator tubes are volumetrically examined.
5. Due to the stress basis analysis ranking of this location, relative to the upper joint canopy location, a stainless steel location for both the Unit 1 and Unit 2 are presented for the CRDM transient section. In addition, the CUF results for the Unit 2 lower canopy seal weld inside location is used to determine a bounding CUF_{en} value for the Unit 2 CRDM assembly.
6. The CUF analysis used the design fatigue curve presented in ASME Code, Section III, Appendix I Figure I-9.1 which is conservative relative to the design fatigue curves provided in NUREG/CR-6909, draft Revision 1 for low-alloy steels.
7. NUREG/CR-6260 location.
8. SIA Report Number 1601007.401 (Proprietary), “Flaw Tolerance Evaluation of the Surry Unit 1 and 2 Hot Leg Surge Line Nozzles Using ASME Code Section XI, Appendix L,” September 2017 determined that the nozzle to hot leg weld is the limiting location based upon NUREG-6909 and cycle projections through subsequent period of extended operation.
9. Not Used.
10. The pressurizer is separated into two transient sections to represent the differences in thermal transients for regions affected by insurge/outsurge events (pressurizer lower head) and those not affected by insurge/outsurge events (pressurizer upper head/shell).
11. The methodology in NUREG/CR-6909, Revision 0 is used for stainless steel and Ni-Cr-Fe alloy materials while the methodology in NUREG/CR-6909, draft Revision 1 is used for carbon and low-alloy steels. For vessels, the methodology in NUREG/CR-6909, Revision 0 is used for stainless steel and Ni-Cr- Fe alloy materials while the methodology in NUREG/CR-6909, draft Revision 1 is used for carbon and low-alloy steels. For piping, the methodology in NUREG/CR-6909, Revision 0 is used for screening.
12. CUF determined by the common basis stress evaluation approach from EPRI Report 1024995, dated 2012.
13. Westinghouse Calculation CN-PAFM-03-46, Revision 1, “Surry 12" Accumulator Nozzle Fatigue Analysis with Environmental Effects,” March 30, 2009. (Reference 4.8-58)
14. Overall effective F_{en} from the modified rate approach calculated per NUREG/CR-6909, Revision 0.
15. Westinghouse Calculation, CN-PAFM-03-47, Revision 1, “Surry 3" Charging Nozzle Fatigue Analysis with Environmental Effects,” March 30, 2009. (Reference 4.8-59)
16. The hot leg location is the bounding sentinel location based upon the crack growth evaluation performed per Appendix L. Refer to Stone & Webster calculation for AOR CUF.
17. Based upon NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,” April 1999. (Reference 4.8-60)
18. The information for this item corresponds to the Unit 2 replacement RV closure head; however, the same location is bounding for the Unit 1 replacement RV closure head.
19. NRC Letter to Stoddard, “Surry Power Station, Units 1 and 2 - Revised License Renewal Commitment Pressurizer Surge Line Weld Inspection Frequency (EPID L-2017-LR0-0078), June 29, 2018.

Table 4.3.4-2 ASME Section XI Appendix L Results

Auxiliary Line	Flaw Configuration	Aspect Ratio (1)	Acceptable Standards Flaw Size Table IWB-3514-2 (a/t) (2)	Final Flaw Size (a/t) (3)	Maximum Allowable End-of-Evaluation Flaw Size (a/t) (4)	Allowable Operating Period (Years)
Safety injection (6-inch diameter line near RCS cold leg)	Axial	8	0.12	0.2354	0.47	80
	Circumferential	9	0.12	0.2158	0.57	80
Residual heat removal (14-inch diameter line)	Axial	71	0.11	0.1209	0.75	80
	Circumferential	11	0.11	0.1256	0.75	80
Spray (4-inch diameter spray piping attached to pressurizer)	Axial	64	0.12	0.1999	0.20	21
	Circumferential	50	0.12	0.5125	0.56	80
Charging (3-inch diameter line near RCS cold leg)	Axial	26	0.12	0.5198	0.52	65
	Circumferential	24	0.12	0.3798	0.38	71
Accumulator (12-inch diameter line near RCS cold leg)	Axial	12	0.11	0.1487	0.42	80
	Circumferential	13	0.11	0.1392	0.61	80
Surge (hot leg surge nozzle)(5)	Axial	6	0.15	0.2789	0.51	60
	Circumferential	6	0.15	0.7322	0.75	47

Notes:

1. Aspect ratio (AR) = constant as the crack grows through the wall thickness.
2. Initial postulated flaw size which is based on ASME Code, Section XI 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.
3. 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 is determined per ASME Code, Section XI Appendix L.
4. 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 less than the maximum allowable end-of-evaluation flaw size.
5. The ASME Code, Section XI, Non-mandatory Appendix L evaluation was approved by the NRC for SLR. (See Reference 4.8-44.)

Table 4.3.4-3 Unit 1 Appendix L Inspections

Location	Line	Weld No.	Last ISI Inspection
Accumulator line – Loop A Cold Leg	12-RC-22-1502	1-02	None
Accumulator line – Loop B Cold Leg	12-RC-23-1502	1-02	None
Accumulator line – Loop C Cold Leg	12-RC-24-1502	1-02	None
Charging line – Loop B Cold Leg	3-CH-1-1502	1-02	None
RHR line – Loop A Hot Leg	14-RH-1-1502	1-06	None
Pressurizer Spray line	4-RC-15-1502	2-24	R23 PT NRI 10/20/2010 UT NRI 10/20/2010
Safety Injection line – Loop A	6-RC-17-1502	1-02	R24 UT NRI 5/17/2012 Limited
Safety Injection line – Loop B	6-RC-19-1502	1-02	R24 UT NRI 5/16/2012 Limited
Safety Injection line – Loop C	6-RC-20-1502	1-02	R25 UT NRI 11/4/2013 Limited
Surge line	12-RC-10-2501R	1-08	For initial license renewal period, inspection results are available once per 40 month period.

Table 4.3.4-4 Unit 2 Appendix L Inspections

Location	Line	Weld No.	ISI Inspection History
Accumulator line – Loop A Cold Leg	12-RC-322-1502	1-02	11/1/1986 PT & UT NI No 3I
Accumulator line – Loop B Cold Leg	12-RC-323-1502	1-02	10/30/1986 PT & UT NI No 3I
Accumulator line – Loop C Cold Leg	12-RC-324-1502	1-02	10/27/1986 PT 100% UT Limited NI No 3I
Charging line – Loop B Cold Leg	3-CH-301-1502	1-02	10/27/1986 PT 5/6/1996 PT
RHR line – Loop A Hot Leg	14-RH-101-1502	1-06	5/2/1985 PT & UT NI No 3I
Pressurizer Spray line	4-RC-315-1502	2-35	R20, 10/23/2006 UT & PT NRI Limited R26 PT 11/2/2015 NRI R26 UT 11/3/2015 NRI
Safety Injection line – Loop A	6-RC-317-1502	1-03	R22 UT 11/17/2009 NRI Limited
Safety Injection line – Loop B	6-RC-319-1502	1-02	R25 UT 4/28/2014 NRI Limited
Safety Injection line – Loop C	6-RC-320-1502	1-02	R23 UT NRI 5/1/2011 Limited
Surge line	12-RC-310-2501R	1-08	For initial license renewal period, inspection results are available once per 40 month period.

4.3.5 REACTOR VESSEL INTERNALS FATIGUE ANALYSES

TLAA Description

The RV internals were designed before ASME Code, Section III, Division 1, Subsection NG was established. Therefore, no CUF values were calculated as part of the original RV internals design. However, as part of engineering evaluations to support Units 1 and 2 operations at measurement uncertainty recapture power uprate conditions, updated structural evaluations were performed for the upper and lower core plates to demonstrate that they would maintain their structural integrity at proposed power uprate conditions. The lower and upper core plates are not part of the reactor coolant system pressure boundary. As part of the structural evaluations, fatigue analyses of the upper and lower core plates were performed to the 1989 edition of ASME Code, Section III, Division 1, subsection NG. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The AOR fatigue CUF results are less than 1.0 (Reference 4.8-61).

Table 4.3.5-1 CUFs for the Reactor Vessel Internals

Component	Cumulative Usage Factor
Lower core plate	0.334
Upper core plate	0.812

TLAA Evaluation:

The MUR power uprate analyses considered various transients that were selected from the transients identified in Table 4.3.1-1.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound 80 years of plant operations. Therefore, the fatigue analyses for the RV internals remain valid for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The fatigue analyses for the RV internals remain valid for the subsequent period of extended operation.

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 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 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.

The EQ program was evaluated against the Division of Operating Reactors (DOR) Guidelines and the basis for equipment qualification is Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment,” (Reference 4.8-62) and IEEE Standard 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations,” (Reference 4.8-63) as codified by 10 CFR 50.49. IEEE 323-1974 provides the criteria for safety related equipment (electrical “Class 1E” equipment) and the basis for categorizing equipment important to safety, and defines environmental service conditions. Therefore, the EQ program includes and identifies electrical equipment that is important to safety and that could be exposed to harsh environment accident conditions, consistent with 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 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).

TLAA Evaluation:

The EQ program implements the requirements of 10 CFR 50.49, as further defined and clarified by the DOR Guidelines and the basis for equipment qualification in Inspection and Enforcement Bulletin (IEB) 79-01B and IEEE Standard 323-1974. 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.

<u>Analytical Methods</u>

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.

<u>Data Collection and Reduction Methods</u>

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 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.

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 requalified 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 requalify 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 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.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on intended functions of EQ components that are the subject of EQ TLAAs will. be adequately managed for the subsequent period of extended operation under the *Environmental Qualification of Electric Equipment* program (B3.3) in accordance with10 CFR 54.21(c)(iii).

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS

The Containments utilize a reinforced concrete design without the use of prestressed tendons. Therefore, loss of prestress is not applicable for the Containments.

4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE ANALYSIS

4.6.1 CONTAINMENT LINER PLATE

TLAA Description:

As discussed in UFSAR Section 15.5.1.8, the steel containment liner was designed to withstand the effects of pressure, temperature, and earthquake loads, including the effect of the subatmospheric operating pressure. Because there was no ASME Code for a steel lined concrete vessel at the time SPS was designed, stress intensity limits and stress category definitions were determined using ASME Code, Section III, 1968 Edition as a guide. The liner stresses and their associated strains were limited to the criteria given in ASME Code, Section III, Paragraph N-1314 and to basic primary stress intensity levels taken from ASME Code, Section III, Table N-421. The accumulated effects of containment liner loading conditions were evaluated in accordance with the ASME Code, Section III, Paragraph N-415, to determine the need for a detailed fatigue analysis.

The evaluation for the original 40 years of operation was based on the following design cycles:

- 1,000 cycles of operating pressure variations
- 4,000 cycles of operating temperature variations
- 20 design earthquake cycles (operating basis earthquake)
- 1 cycle of accident pressure
- 1 cycle of accident temperature
- 10 cycles of hypothetical earthquake (safe shutdown earthquake)

During the original 40 years of operation, anticipated loading cycles for the Containment liner were as follows:

- Operating pressure variations from 9.5 psia to 14.7 psia were expected to occur not more than 100 times since personnel access is permitted under subatmospheric conditions.
- Temperature variations from 70°F to 105°F, resulting from seasonal swings and plant shutdowns, were expected to occur not more than 400 times.
- The design earthquake was expected to produce tremors to the extent of not more than 8 to 10 cycles and the hypothetical earthquake not more than 4 to 5 cycles.

TLAA Evaluation:

For the initial and subsequent periods of extended operation, the design cycles and anticipated cycles were extrapolated from the original design to the values shown in Table 4.6.1-1. (Reference 4.8-64).

Table 4.6.1-1 Containment Liner Load Cycles

	Design Cycles		Anticipated Cycles	
	60 years	80 years	60 years	80 years
Operating Pressure	1,500	2,000	150	200
Operating Temperature	6,000	8,000	600	800
Design Earthquake (OBE)	30	40	12 to 15	16 to 20

The six conditions in ASME Code, Section III, Subsection N-415.1 were evaluated using the design cycles shown in Table 4.6.1-1 to determine the need for a detailed fatigue analysis. Effects of the Appendix J, Type A pressure tests were included in the evaluation. Each of the six conditions was shown to be satisfied. No detailed fatigue analysis is required for the Containment liner due to stress fluctuations caused by pressure, temperature, and design earthquake cycles during an 80-year plant operating term. The increase in the anticipated number of cycles due to the subsequent period of extended operation is acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The fatigue waiver analyses associated with the Containment liner plate have been revised and projected to remain valid for the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.6.2 METAL CONTAINMENT

Each unit has a concrete containment with a metal liner. Therefore, the topic of metal containment fatigue analysis is not applicable.

4.6.3 CONTAINMENT PENETRATIONS FATIGUE ANALYSIS

There are no TLAAs for Containment penetrations since these were not analyzed for cyclic fatigue. The penetrations are designed for a one-time load due to the collapse of the connecting pipe. All penetrations, regardless of size, are anchored in the reinforced concrete containment wall. The anchor strength is equal to the full yield strength of the pipe with regard to torsion, bending, and shear, and to the maximum possible pipe jet reaction. All stresses induced in the liner by these combinations of loadings are only those reflected by the resulting distortions in the reinforced concrete containment wall, and are minor in intensity, so loads will not be imposed on the liner, thereby preserving its integrity. (Reference 4.8-64) The normal operating loads are much smaller than the collapse loads of the pipe, including both restrained piping system thermal expansion loads, as well as local thermal expansion loads. The stresses due to the normal operating conditions are below the endurance limit. Therefore, the penetrations will not fail due to fatigue. This evaluation remains valid for the subsequent period of extended operation.

4.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

The following plant-specific safety analysis involve time-limited assumptions defined by the current operating term of the plant 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)
- *Spent Fuel Pool Liner Fatigue Analysis* (Section 4.7.4)
- *Piping Subsurface Flaw Evaluations* (Section 4.7.5)
- *Reactor Coolant Pump Code Case N-481* (Section 4.7.6)
- *Cracking Associated with Weld Deposited Cladding* (Section 4.7.7)
- *Steam Generator Tube High Cycle Fatigue Evaluation* (Section 4.7.8)
- *Steam Generator Tube Wear Evaluation* (Section 4.7.9)

4.7.1 CRANE LOAD CYCLE LIMITS

TLAA Description:

A review of design specifications for cranes within the scope of subsequent license renewal was performed to identify those cranes that were designed or otherwise required to meet the intent of Crane Manufacturers Association of America (CMAA) Specification 70-1975, “Specifications for Electric Overhead Traveling Cranes,” (Reference 4.8-65) and, therefore, have a defined service life as measured in load cycles. The defined service life as measured in load cycles is identified as a TLAA.

TLAA Evaluation:

Method of Evaluation-Scope

The cranes potentially subject to TLAA are those subject to NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants” (Reference 4.8-66). As documented in UFSAR Section 9B.2, the following load handling systems are consistent with NUREG-0612:

- Containment polar cranes
- Containment annulus monorail
- Containment jib cranes
- Fuel building motor-driven platform
- Auxiliary building 10-ton monorail (27 foot level)
- Auxiliary building 5-ton monorail (13 foot level)
- Residual heat removal pump motor lifting lugs
- Spent fuel crane

The following NUREG-0612 load handling systems have been designed to or evaluated as meeting the requirements of ANSI Standards B30.11-1973, “Monorail Systems and Underhung Cranes” (Reference 4.8-67) and B30.16-1973, “Overhead Hoists” (Reference 4.8-68) or ASME Standard HST-4, “Performance Standard for Overhead Electric Wire Rope Hoists” (Reference 4.8-69). These standards do not specify load cycle limits:

- Containment jib cranes
- Containment annulus monorails
- Auxiliary Building 10-ton monorail (27 foot level)
- Auxiliary Building 5-ton monorail (13 foot level)
- Fuel Building motor-driven platform

The following NUREG-0612 load handling systems have been evaluated to the load cycle requirements of CMAA Specification 70 or its historical equivalent, Electric Overhead Crane Institute (EOCI) Specification 61, “Specifications for Electric Overhead Traveling Cranes” (Reference 4.8-70):

- Containment polar cranes
- Spent fuel crane

Thus, the Containment polar cranes and the spent fuel crane are identified as subject to TLAA for load cycles.

Method of Evaluation - Acceptance Criteria

CMAA Specification 70 presents the bounding combinations of the number of load cycles and mean effective load factors for each service class. These define the acceptable service limits for the TLAA. The plant response to NUREG-0612, as guided by NRC Generic Letter 81-07, “Control of Heavy Loads,” (Reference 4.8-71) indicates that the Containment polar cranes and spent fuel crane were designed and fabricated in accordance with EOCI Specification 61 and compares that design approach to that of CMAA Specification 70, which has superseded EOCI Specification 61. The conclusion reached in the response to NRC Generic Letter 81-07 is that Containment polar cranes and the spent fuel crane satisfy the design intent of CMAA Specification 70. CMAA Specification 70 provides guidance regarding fatigue but EOCI Specification 61 does not explicitly address fatigue failure. The following paragraph describes the method of selecting the service class from CMAA Specification 70 that corresponds to the service class originally specified from EOCI Specification 61. This service class is used with CMAA Specification 70, Table 2.8-1 to identify the applicable number of load cycles for that specific service class.

The plant specifications for the Containment polar cranes and the spent fuel crane require design to EOCI Specification 61 Service Class A described as the following:

> “Standby service: For such use as powerhouse, pump rooms, motor rooms, transformer repair, etc. where the crane is used very infrequently. These cranes must be substantially designed to handle expensive loads.”

The corresponding service class in CMAA Specification 70 is Class A service, which is defined as the following:

> “Standby or Infrequent service: This service class covers cranes which may be used in installations such as powerhouses, public utilities, turbine rooms, motor rooms and transformer stations where precise handling of equipment at slow speeds with long, idle periods between lifts required. Capacity loads may be handled for initial installation of equipment and for infrequent maintenance.”

Based on the comparison of service classes described in the original design specification (EOCI Specification 61) to CMAA Specification 70, the applicable service class is Class A.

CMAA Specification 70 states that a range of load cycles from 20,000 to 100,000 was considered for cranes in class A (Standby) service thus establishing the envelope for acceptable number of load cycles for this TLAA. The total projected load cycles for the Containment polar cranes and the spent fuel crane based on past and future use is summarized in Table 4.7.1-1.

Table 4.7.1-1 Evaluation Summary of Crane Operation

Crane	CMAA Service Class	Maximum Number of Load Cycles	Projected Number of Load Cycles for 80 years	Valid for 80 years
Unit 1 Containment Polar Crane	Class A	100,000	2,726	Yes
Unit 2 Containment Polar Crane	Class A	100,000	2,620	Yes
Spent Fuel Crane	Class A	100,000	34,600	Yes

<u>Containment Polar Crane Evaluation:</u>

The Containment polar cranes were designed to meet the intent of class A (Standby) Service. The CMAA Specification 70 class A service design includes consideration of 100,000 load cycles during operation of the crane. Recurring loads associated with the Containment polar cranes that are in excess of 5% of crane capacity are presented in Table 4.7.1-2 together with infrequent loads associated with initial construction and major maintenance. The total projected number of these load cycles is approximately 2,726 for Unit 1 and 2,620 for Unit 2 over the 80-year operating term of the plant. Since the total number of expected load cycles is considerably less than the maximum number of load cycles of 100,000 considered for Service Class A in CMAA Specification 70, the TLAA for the Containment polar cranes remains valid.

Table 4.7.1-2 Evaluation of Containment Polar Crane Operation

Heavy Load Description[a]	Approximate Load Weight (tons)[a]	Frequency	Number of Refuel Cycles[b]	Number of Lifts Over Plant Life
Reactor vessel head with lifting rig (Unit 1)	131	2/refuel cycle	53	106
Control Rod Drive (CRD) missile shield (Unit 1)	36.5	2/refuel cycle	53	106
Reactor vessel head with lifting rig and CRD missile shield (Unit 2)	132.6	2/refuel cycle	53	106
Reactor upper internals and lifting rig (each unit)	52	2/refuel cycle	53	106
Reactor coolant pump motor and sling (each unit)	41	2/refuel cycle	53	106
Reactor vessel seal ring and lifting device (each unit)	12.2	2/refuel cycle	53	106
Containment floor concrete plugs (16 total for each unit)	1 to 31.5	32/refuel cycle	53	1,696
Large equipment placement lifts - Initial construction and major equipment replacement	Variable	500 over life		500
80-year total estimated load lifts (Unit 1 / Unit 2)				2,726/2,620

Notes:

(a) Load descriptions and weights per UFSAR Table 9B.2-1 (excluding loads less than 5% of crane capacity).

(b) 28 refuel cycles each plant through spring 2018, 18 month cycles projected through 80 years.

Spent Fuel Crane Evaluation:

The spent fuel crane was designed for class A (Standby) Service. The CMAA Specification-70 class A service design includes consideration of 100,000 load cycles during crane operation. Recurring loads associated with the spent fuel crane are projected at approximately 33,300 for the 80-year operating term of the plant using the experience and expectations that were used in initial license renewal. Spent fuel crane lifts associated with the long-term disposition of spent fuel are projected to be approximately 1,260. The total load cycles expected from both refueling and long-term spent fuel storage operations of 34,560 is considerably less than the maximum number of load cycles of 100,000 considered for Service Class A in CMAA Specification-70; therefore, the TLAA for the spent fuel crane remains valid.

Table 4.7.1-3 Evaluation of Spent Fuel Crane Operation

Heavy Load Description	Approximate Load Weight (tons)	Number of Lifts over Plant Life
Spent Fuel Cask (incl. Fuel, Yoke, Lid)	125	1,260
Spent Fuel Cask Lid and Tool	6.9	
Irradiated Specimen Cask	5.7	
Historical lifts (25,000 estimated to support refueling for first 60 years as presented in initial license renewal application, proportioned to 80 years.)		33,300
80-year total estimated load lifts		34,560

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The Containment polar cranes and spent fuel crane load cycle evaluation has been demonstrated to remain valid through the subsequent period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.7.2 REACTOR COOLANT PUMP FLYWHEEL FATIGUE CRACK GROWTH ANALYSES

TLAA Description:

The reactor coolant pump (RCP) flywheel is discussed in UFSAR Section 18.3.5.2, which references WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination” (Reference 4.8-72).

The RCP flywheel inspection is specified in Technical Specification 4.2-1. NRC Letter dated June 21, 2005, “Surry Power Station, Units 1 and 2 - Issuance of Amendments to Extend the Inspection Interval for Reactor Coolant Pump Flywheels (TAC Nos. MC4215 and MC4216),” (Reference 4.8-73), amended the Technical Specification to extend the inspection interval for the RCP flywheel from 10 years to 20 years, consistent with the evaluation in WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination” (Reference 4.8-74). The inspection is a qualified in-place UT examination over the volume from the inner bore of the RCP flywheel to the circle of one-half the outer radius or a surface examination (magnetic particle testing and/or liquid penetrant testing) of the exposed surfaces defined by the volume of the disassembled RCP flywheels.

Considering the RCP flywheel probability of failure is part of the current licensing basis and is used to support safety determinations, and the probability of failure was based upon 60-year assumptions and 6,000 pump starts and stops, this fatigue analysis has been identified as a TLAA requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

RCP start and stop cycles are projected in Table 4.7.2-1.

Table 4.7.2-1 RCP Start/Stop Cycle Projections for 80 Years

Projected Heatup/Cooldown Cycles (Table 4.3-1)	Estimated RCP Start/Stop Cycles per Heatup/Cooldown Cycle[(a)]	Total Projected RCP Start/Stop Cycles for 80 years
193	6	1,158

Notes:

(a) 6 start/stop cycles is based on operator interviews and is less than 100 start/stop cycles assumed in WCAP-15666 demonstrating operational margin.

During normal operation, the RCP flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions which may result in overspeed of the RCP increase both the potential for failure and the kinetic energy. The aging effect of concern is fatigue crack initiation in the RCP flywheel bore keyway.

An evaluation of the probability of failure over the subsequent period of extended operation was performed. The evaluation is documented in PWROG-17011-NP, “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 4.8-75)”. PWROG-17011-NP confirms that the analysis under WCAP-14535-A and WCAP-15666-A justifying inspection of the RCP flywheel once every 20-years remains appropriate for application up to 80 years of operation.

The fatigue crack growth calculations assumed 6,000 cycles of RCP start and stop for the 80-year plant life which bounds the projected cycle counts of 1,158 start/stops. The fatigue crack growth is negligible over an 80-year life of the RCP flywheel, even when assuming a large initial crack length.

The evaluation demonstrates that the RCP flywheel design has a high structural reliability with a very high flaw tolerance and negligible fatigue flaw crack extension over an 80-year service life.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The RCP flywheel fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7.3 LEAK-BEFORE-BREAK

TLAA Description:

The aging effect identified in this TLAA is thermal aging of CASS material resulting in embrittlement, that is, a decrease in the ductility, impact strength, and fracture toughness and an increase in hardness and tensile strength of the material. This TLAA uses fully-aged fracture toughness properties.

The fatigue crack growth evaluation performed in WCAP-15550-P, Revision 1 (Reference 4.8-76) 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 fatigue crack growth evaluation was based on a generic model with representative design transient and cycles that are applicable to SPS.

10 CFR 50, Appendix A, Criterion 4, 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 nuclear power plant piping are sufficiently tough that even a large through-wall crack would remain stable and would not result in a double-ended pipe rupture.

Updated Final Safety Analysis Report Sections 18.3.5.3 and 14.5.1.2 discuss LBB, which applies only to the reactor coolant system (RCS) primary loop piping.

To maintain the LBB design basis for the plant, the LBB evaluation needed to be performed for an 80-year plant life.

TLAA Evaluation:

WCAP-15550-P (Revision 0), “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for the Surry Units 1 and 2 Nuclear Power Plants for the License Renewal Program,” had demonstrated compliance with LBB technology for the RCS piping for 60-year plant life based on a plant-specific analysis. Subsequently, a LBB evaluation was performed for the MUR power uprate. WCAP-15550-NP (Revision 1), “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 years) Leak-Before-Break Evaluation” (Reference 4.8-77), performed the evaluation for 80 years. The results of the MUR power uprate analysis are included in WCAP-15550-NP (Revision 1).

The analysis documented the plant-specific geometry, loading, and material properties used in the fracture mechanics evaluation. Mechanical properties were determined at operating temperatures. Since the piping systems include cast austenitic stainless steel, fracture toughness considering thermal aging was determined for each heat of material. Fully aged fracture toughness properties were used for the LBB evaluation. The fully aged condition is applicable for plants operating beyond

15 EFPY for the CF8M materials (elbows for Units 1 and 2). As of January 2017, Units 1 and 2 were operating at 33.78 and 33.69 EFPY, respectively.

The updates performed for WCAP-15550-NP included a recalculation of delta ferrite and fracture toughness properties based on NUREG/CR-4513, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems” (Reference 4.8-78). The chemistry data for the fracture mechanics parameters are provided in WCAP-15550-P (Revision 0). Fracture toughness parameters were recalculated using information from NUREG/CR-4513.

Fatigue crack growth rate laws were used from the ASME Code, Section XI, for the ferritic steel and stainless steel. The fatigue crack growth rate laws were all structured for applicability to pressurized water reactor environments, and are still applicable for an 80-year assessment. The current piping loads and stresses are unchanged from WCAP-15550 (Revision 0) and are used in WCAP-15550 (Revision 1). The evaluation methodology from Revision 0 was used in Revision 1.

The fatigue crack growth analysis used CLB cycles (40-year design cycles). As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue crack growth analysis for the LBB analysis has been projected to the end of the period of extended operation.

The analysis provides a fracture mechanics demonstration of reactor coolant system 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 4.8-79). The analysis justifies the elimination of reactor coolant system primary loop pipe breaks from the structural design basis for the 80-year plant life as follows:

a. Stress corrosion cracking is precluded by use of fracture resistant materials in the piping system and controls on reactor coolant chemistry, temperature, pressure, and flow during normal operation. There is no Alloy 82/182 material present in the welds for reactor coolant system primary loop piping.
b. Water hammer should not occur in the reactor coolant system piping because of system design, testing, and operational considerations.
c. The effects of low and high cycle fatigue on the integrity of the primary piping are negligible.
d. Margin exists between the leak rate of small stable flaws and the capability of the reactor coolant system pressure boundary leakage detection system.
e. Margin exists between the small stable flaw sizes of item (d) and larger stable flaws.
f. Margin exists in the fully-aged material properties to demonstrate stability of the critical flaws after 80 years of operation.

The critical postulated flaw locations are shown to be stable because of the ample margins described in d, e, and f above.

Based on the above, 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 pipe breaks need not be considered in the structural design basis for Units 1 and 2 for the 80-year plant life.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The assessment performed in WCAP-15550-P, Revision 1 determined that the crack stability results, fracture toughness, and fatigue crack growth results are acceptable for 80 years of plant operation. Therefore, the LBB analysis is projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.4 SPENT FUEL POOL LINER FATIGUE ANALYSIS

TLAA Description:

The spent fuel pool liner located in the Fuel Building is needed to prevent a leak to the environment. A design calculation (Reference 4.8-80) has been identified which documents that the spent fuel pool design meets the general industry criteria of ASME Code, Section III, Subsections NB-3222.2, NB-3222.4, and NB-3228.5, 2010. (Reference 4.8-81) The calculation includes a fatigue analysis to add a further degree of confidence.

TLAA Evaluation:

As discussed in UFSAR Section 9.5.1, the fuel pool water temperature is continuously indicated in the control room, and an alarm in the control room alerts the operator prior to this temperature reaching 140°F.

The fuel pool cooling system has the capability to:

1. Maintain the temperature of the fuel pool water below 140°F during a normal core offload condition commencing 100 hours after shutdown. A normal core offload condition is a planned offload of up to a full core. The most limiting condition for normal core offload is a full core offload following refueling of the other unit.
2. Maintain the temperature of the fuel pool water below 170°F during an abnormal core offload condition commencing 100 hours after shutdown. An abnormal core offload is an unplanned offload of up to a full core. The most limiting condition for an abnormal core offload is an unplanned full core offload following back-to-back refuelings of both units

The spent fuel pool liner was designed for three conditions:

Condition 1: Normal core offload, maximum temperature = 140°F

Condition 2: Abnormal core offload, maximum temperature = 170°F

Condition 3: Faulted Condition, maximum temperature = 212°F

The number of thermal cycles corresponding to each of these conditions is reflected in Table 4.7.4-1 below.

Table 4.7.4-1 Spent Fuel Pool Liner Thermal Cycles

Condition	60 years	80 years	Allowable
1	81	108	1200
2	8	11	20
3	1	1	9

The number of thermal cycles corresponding to Conditions 1 and 2 for an 80-year plant operating term were determined by extrapolating from 60 to 80 years. Since the faulted Condition 3 (with the maximum temperature of 212°F) is an extreme case which is not expected to happen during the subsequent period of extended operation, the number of cycles for Condition 3 was not proportionally increased and only a single cycle was considered for faulted Condition 3. Considering the most conservative case of fatigue effects, evaluated using fatigue criteria for an 80-year plant operating term, the maximum allowable numbers of cycles were estimated in the original calculation (Reference 4.8-82) as 1200, 20, and 9 for Conditions 1, 2, and 3, respectively.

The thermal stresses in the spent fuel pool liner due to conservatively assumed temperature gradients and thermal cycles during an 80-year plant operating term satisfy the requirements of the ASME Code, Section III, Subsections NB-3222.2, NB-3222.4, and NB-3228.5. Therefore, fatigue criteria are satisfied and no compensatory action is required.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

Fatigue analysis associated with the spent fuel pool liner has been projected to the end of the subsequent period of extended operation.

4.7.5 PIPING SUBSURFACE FLAW EVALUATIONS

TLAA Description:

Piping subsurface flaw evaluations are discussed in UFSAR, Section 18.3.5.5. Initial license renewal identified calculations that address piping subsurface indications (detected by inspections that were conducted during original plant construction, and that were performed in accordance with ASME Code, Section XI, which provided the acceptance criteria for various flaw orientations, locations, and sizes). The calculations determined the number of thermal cycles required for the flaws to reach an unacceptable size. This TLAA evaluates the effects of fatigue on previously disclosed subsurface flaws to ensure operational margin through the subsequent period of extended operation.

TLAA Evaluation:

The piping subsurface calculations were reassessed for 80 years of operation. The 80-year calculations described in LTR-PAFM-17-14, “Subject: Surry Units 1 and 2 Piping Subsurface Flaw Evaluation for 80 Years of Service, Subsequent License Renewal” (Reference 4.8-83), were based on the fatigue crack growth equations of ASME Code, Section XI, Appendix A and Appendix C.

The analysis considered three topics which were updates to stresses, changes in stress intensity factor calculations, and changes in fatigue crack growth rates since the original analysis performed in 1972. Stress intensity factors were updated, where necessary. The piping subsurface indication allowable and estimated cycles are depicted in Table 4.7.5-1.

Table 4.7.5-1 Piping Subsurface Indication Allowable and Estimated Cycles

Item	Line	Stresses (psi)	Stress Intensity Factor (K_I)	Allowable Cycles[1]	Estimated Cycles for 80 Years
1 & 3	Fire Protection	15,908	recalculated[2]	6,255	40
2	Feedwater (slag inclusion)	11,391	original	422,874	120
4	Feedwater (backing ring)	5,914	original	3,886,003	120
5	Seismic I Category Piping	27,700	recalculated[2]	70,390	120

1. All Allowable Cycles to reach maximum flaw size were reduced from original analysis.
2. The latest stress intensity factor used in the industry based on API-579-1, “Fitness-For-Service,” (Reference 4.8-84) was applied to the evaluation.

The calculated allowable cycles were all well above the estimated cycles that are expected to occur for these lines in an 80-year life (allowable cycles are 150 times greater than estimated cycles for Items 1 & 3, and at least 500 times greater than the estimated cycles for Items 2, 4 and 5). Therefore, there is no need for any future repair, replacements, or re-evaluations of these particular indications and lines discussed.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The piping subsurface flaws detected during original plant construction have been re-evaluated for 80-year life and shown to have allowable cycles well above the estimated cycles expected for the piping components of interest and are therefore projected through the subsequent period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.7.6 REACTOR COOLANT PUMP CODE CASE N-481

TLAA Description:

The SPS reactor coolant pumps (RCPs) are model 93A with SA-351, Grade CF-8 pump casings. Periodic volumetric inspections of the welds of the reactor coolant system (RCS) primary loop pump casings of commercial nuclear power plants were specified by ASME Code, Section XI. The inspections result in large radiation exposure (man-rem), which is a personnel safety concern. Since the pump casings were inspected prior to being placed in service, and no significant mechanisms exist for crack initiation and propagation, it has been concluded that the inservice volumetric inspection can be replaced with an acceptable alternate inspection. In recognition of this, ASME Code Case N-481, “Alternative Examination Requirements for Cast Austenitic Pump Casings” (Reference 4.8-85), provides an alternative to the volumetric inspection requirement. ASME Code Case N-481 allows the replacement of volumetric examinations of RCS primary loop pump casings with fracture mechanics-based integrity evaluations (Item (d) of the code case) supplemented by specific visual examinations.

The initial evaluation included in WCAP-13045, “Compliance to ASME Code Case N-481of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System” (Reference 4.8-86), has been updated to validate saturated fracture toughness values are used for assessment of the integrity of the pump casing through the subsequent period of extended operation. Validation of this fracture mechanics evaluation was specified in ASME Code Case N-481 as a condition to conduct visual examinations in lieu of the volumetric inspections specified in ASME Code, Section XI.

TLAAs related to ASME Code Case N-481 have been identified: thermal aging of cast austenitic stainless steel (CASS) and its consequence on fatigue crack growth. ASME Code Case N-481 is discussed in UFSAR, Section 18.3.5.6.

TLAA Evaluation:

ASME Code Case N-481 allowed the replacement of volumetric examination of RCS primary loop pump casings with a safety and serviceability fracture mechanics-based integrity evaluation supplemented by specific visual inspections. WCAP-13045 presents the integrity evaluation that was performed to demonstrate compliance with ASME Code Case N-481. (WCAP-13044, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System" (Reference 4.8-87), presents the non-proprietary information in WCAP-13045.) The fracture toughness properties are presented in WCAP-13045.

Since the time WCAP-13045 was published, the ASME Code table Category B-L-1, Item B12.10, has been updated to be consistent with the guidance of ASME Code Case N-481 in mandating visual inspections of the primary loop pump casings. In March 2004, ASME Code Case N-481 was annulled by ASME, and the information in the code case was implemented into the 2008 addenda of ASME Code, Section XI. However, the technical basis of the WCAP-13045 report was based on experience with evaluations performed for an assumed 40-year life. With subsequent license renewal extending plant service life to 80 years, the integrity evaluations in WCAP-13045 needed to be reviewed and confirmed applicable for 80 years of operation.

The fracture mechanics integrity assessment in PWROG-17033-NP, "Update for Subsequent License Renewal: WCAP-13045,'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems'" (Reference 4.8-88), as well as the requirements of ASME Code Case N-481 (now incorporated into the ASME Code, Section XI were reaffirmed to demonstrate that the visual inspections, in lieu of volumetric inspections, for pump casings remain valid for an 80-year life.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

Comparisons of RCS casing loads with the screening loads have been made. The stability of the flaws postulated in the RCS primary loop pump casings has been established by evaluating the necessary material properties against the saturated (fully aged) fracture toughness values. Thus, ASME Code Case N-481 is satisfied for the subsequent period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.7.7 CRACKING ASSOCIATED WITH WELD DEPOSITED CLADDING

TLAA Description:

Reactor vessel underclad cracking involves cracks in base metal forgings immediately beneath austenitic stainless steel cladding which are created as a result of the weld-deposited cladding process. Westinghouse performed an analysis of flaw growth associated with underclad cracking in 1971, concluding that RV integrity could be assured for the original plant license term. Underclad cracking only requires analysis if examinations have detected flaws (the analysis is not used to postulate flaws). Indications that could be representative of underclad cracking flaws have been detected under CN-AMLRS-10-3 (Proprietary), Revision 0, “Implementation of WCAP-16168-NP-A, Revision 2, for Surry Units 1 and 2" (Reference 4.8-89); therefore, the underclad cracking analysis is considered a TLAA, and the effects of fatigue on underclad cracking is evaluated through the subsequent period of extended operation.

Reactor vessel underclad cracking is discussed in UFSAR Section 18.3.2.2, which references WCAP-15338-A, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants” (Reference 4.8-90).

TLAA Evaluation:

To extend this analysis to 60 years in support of initial license renewal, WCAP-15338-A provided an updated analysis of underclad cracking for Westinghouse units. WCAP-15338-A included fatigue crack growth analysis and ASME Code, Section XI allowable flaw size evaluations for typical Westinghouse vessels and found that the expected maximum flaw size predicted by the crack growth analysis is less than the ASME Code, Section XI allowable flaw size. WCAP-15338-A assumed 1.5 times the numbers of cyclic and transient loads assumed for the original 40-year life, and demonstrated that these effects were acceptable for a 60-year life. The NRC in their safety evaluation of this WCAP stated that any Westinghouse Owners Group plant may reference this report in a license renewal application to satisfy the requirements of 10 CFR 54.21(c)(1) regarding evaluation of TLAAs for RV components.

PWROG-17031-NP, “Update for Subsequent License Renewal: WCAP-15338-A, ’A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants’ ” (Reference 4.8-91), updated the 60-year fatigue crack growth analysis in WCAP-15338-A and confirmed the analysis remains appropriate for application to subsequent license renewal, up to 80 years of operation. More specifically:

- Revised the fatigue crack growth analysis for 80 years of operation. 40 years of design cycles bound the 80 year projected cycles as shown in Table 4.3.1-1.
- Confirmed fracture toughness values used in Appendix A of WCAP-15338-A are bounding for 80 years of operation.
- Updated operating experience as discussed in Sections 2 and 3 of WCAP-15338-A.
- Included discussion of state of the art inspection techniques and capabilities for detecting and characterizing cracks associated with manufacturing processes as well as those due to potentially service-induced mechanisms.

The fatigue crack growth analysis methodology of ASME Code, Section XI, Appendix A, was used, with the entire set of design transients applied over an 80-year period. The cycles applicable to 40 years of operation were conservatively multiplied by a factor of 2 to account for 80 years of operation. Underclad cracks found during pre-service and inservice inspections have been evaluated in accordance with the acceptance criteria of ASME Code, Section XI. The observed underclad cracks are very shallow, confined in depth to less than 0.295 inch and have lengths up to 2.0 inches. The fatigue crack growth assessment for these small cracks shows very little extension over 80 years, even if they were exposed to the reactor water and with crack tip pressure of 2,500 psi. For the worst-case scenario, a 0.30 inch deep continuous axial flaw in the beltline region would grow to 0.43 inch after 80 years. The minimum allowable axial flaw size for normal, upset and test conditions is 0.67 inch and for emergency and faulted conditions is 1.25 inches. Since the maximum flaw depth of 0.43 inch after 80 years of fatigue crack growth is below the minimum allowable flaw size of 0.67 inch, underclad cracks of any shape are acceptable for service for 80 years, regardless of the size or orientation of the flaws. Therefore, it may be concluded that underclad cracks are of no concern relative to structural integrity of the RV for a period of 80 years. The number of transient cycles assumed in PWROG-17031-NP bound the projected cycles in 80 years presented in Table 4.3.1-1. The fatigue crack growth analysis showed that little or no growth would be expected, and all the flaws were acceptable to the standards of the ASME Code, Section XI, so no further evaluation was required. As stated in PWROG-17031-NP, assuming transient cycles linearly scale from 60 to 80 years, the maximum usage factor would be 0.053. This shows that the likelihood of fatigue cracks initiating during service is very low, even for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

Cracking associated with weld deposited cladding has been projected to the end of the subsequent period of extended operation.

4.7.8 STEAM GENERATOR TUBE HIGH CYCLE FATIGUE EVALUATION

TLAA Description:

Early industry operating experience regarding tube fatigue was limited to steam generators (SGs) with carbon steel, drilled tube support plates (TSPs). The first such fatigue failure occurred in 1987 at North Anna Power Station (NAPS) Unit 1 in the Model 51 SGs. Several other failures attributed to fatigue have occurred since 1987 at other plants containing carbon steel TSPs including Mihama Unit 2 and Indian Point Unit 3. The driving mechanism in each occurrence was attributed to flow-induced vibration of the failed tube. Operating experience in French SGs implied that there is a potential for fatigue-related tube failures in SGs with broached, stainless steel TSPs and that deposit accumulation may have been a significant factor, influencing tube vibration behavior.

Following the steam generator tube rupture at NAPS, the NRC issued Bulletin 88-02, “Rapidly Propagating Fatigue Cracks in Steam Generator Tubes” (Reference 4.8-92) requiring licensees to evaluate SG tubes that are unsupported by an Anti-Vibration Bar (AVB), or tubes that are subject to significant flow peaking due to non-uniform insertion of the AVBs. The purpose of the evaluation was to identify if there is a potential for possible fatigue-related failure during the lifetime of the SG. The SGs in Unit 1 and Unit 2 had been replaced in 1981 and 1980, respectively. The degradation mechanism that caused failure of the NAPS SG tubes was determined not applicable to the replacement SGs.

More recently Westinghouse Electric Company issued Westinghouse Nuclear Safety Advisory Letter (NSAL) NSAL-12-7, Revision 0, “Insufficient Insertion of Anti-Vibration Bars in Alloy 600 TT Steam Generators with Quatrefoil Tube Support Plates,” (Reference 4.8-93). The NSAL identified that fluid induced vibration and associated displacements of the SG tubes caused by the thermal-hydraulic characteristics of the secondary side of the steam generator may create a potential for Steam Generator Tube Fatigue. This potential for tube fatigue of the steam generator tubes must be evaluated and/or managed. Steam generator tube fatigue meets the criteria for TLAAs and must be evaluated for 80 years of operation.

This TLAA validates that the concern of flow induced vibration will not lead to high cycle fatigue failure through the subsequent period of extended operation.

TLAA Evaluation:

WCAP-18379-P, “Surry Units 1 and 2 Steam Generator U-Bend Tube Vibration and Fatigue Assessment” (Reference 4.8-94) evaluated the SG tubes that are unsupported by an AVB which is contrary to the design requirements, or tubes that are subject to significant flow peaking due to non-uniform insertion of the AVBs, to determine if they are subject to possible fatigue related failure during the planed 80 years of plant life.

The EPRI generic Model 51F methodology used in the new analysis is the same as the methodology used to satisfy the analysis requirements of NRC Bulletin 88-02.

The new fatigue analysis focuses on the SG tubes in Rows 6 through 11, identified as potentially susceptible to fatigue. The fatigue analysis was performed to justify operation until the end of a 60-year and 80-year plant lifetime for the Units 1 and 2 SGs, considering the SGs were replaced. Based on this analysis process, it was concluded that for tubes in the pinned TSP condition with no occlusion, none of the unsupported tubes identified in the Units 1 and 2 SGs would potentially be at risk of fatigue related failure during the anticipated 60-year and 80-year plant lifetimes. A stress and fatigue analysis was performed for the bounding tube(s) in each tube row. It was also concluded that no unsupported tubes that are in the pinned condition are at risk of fatigue related failure with moderate levels of TSP occlusion (20.7% weighted) for up to the anticipated 80-year plant lifetimes. The results show that fatigue failure of unsupported SG tubes within the U-bend is not predicted throughout the 60-year and 80-year operating lifetimes for Units 1 and 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The new fatigue analysis demonstrates that all unsupported tubes are acceptable without remediation through 80 years. This evaluation is projected through the subsequent period of extended operation and this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.9 STEAM GENERATOR TUBE WEAR EVALUATION

TLAA Description:

As part of the MUR power uprate, the impact of changes to the secondary side fluid velocity and density were evaluated. The pre-MUR power uprate calculated tube wear is 1.1 mils corresponding to 40 years of operation. The expected tube wear over 60 years of operation is less than 2 mils.

TLAA Evaluation:

The tube wear evaluation, CN-SGDA-02-121, "The Effect of an Uprate to 2609 MWt NSSS Power for Surry Units 1 and 2 on Steam Generator Tube Wear" (Reference 4.8-95) determined that less than 2 mils of wear is expected over 60 years of steam generator operation considering changes in secondary side fluid velocity and density related to MUR power uprate operating conditions. The expected replacement steam generator operating time at the end of 60 years of plant operation is 53 years with approximately 24 years in the uprated condition, i.e., uprate in 2009 with operation to 2033. Over 60 years of operation, the projected wear is still well below the tube wall margin [of 40% through-wall wear depth or 20 mils]. Hence, as shown in WCAP-18341-P, to increase the operating term from 60 years to 80 years, the calculated tube wear remains acceptable. Nonetheless, the steam generator tube wear will be managed by the *Steam Generators* program (B2.1.10) using the existing steam generator eddy current inspection consistent with NEI 97-06, "Steam Generator Program Guidelines" (Reference 4.8-96)

TLAA Disposition: 10 CFR 54.21(c)(iii)

The new wear evaluation for 60-year operation under MUR power uprate conditions demonstrates wear of the steam generator tubes will be acceptable through 80 years of plant operation. Nonetheless, the steam generator tube wear will be managed by the *Steam Generators* program (B2.1.10).

4.8 REFERENCES FOR SECTION 4 TLAAS

4.8-1 ASTM E185, "Standard Practice for Design of Surveillance Programs for Light-Water Moderated Nuclear Power Reactor Vessels."

4.8-2 PWROG-16045-NP, Revision 0, "Determination of Unirradiated RT_{NDT} and Upper Shelf Energy Values of the Surry Units 1 and 2 Reactor Vessel Materials," March 2017.

4.8-3 WCAP-18028-NP, Revision 1, "Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 & 2," April 2018.

4.8-4 WCAP-18242-NP, Revision 2, "Surry Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal," July 2018.

4.8-5 ASTM E208, "Standard Test Method for Conducting Drop-Weight Test to Determine Nil-Ductility Transition Temperature of Ferritic Steels."

4.8-6 ASME Code, Section III, "Rules for Construction of Nuclear Facility Components."

4.8-7 BAW-2308, Revision 1-A SE, "Final Safety Evaluation for Topical Report BAW-2308, Revision 1, 'Initial RT_{NDT} of Linde 80 Weld Materials,'" August 4, 2005.

4.8-8 NUREG-1766, "Safety Evaluation Report Related to the License Renewal of North Anna Power Station, Units 1 and 2, and Surry Power Station, Units 1 and 2," December 2002. (ML030160804)

4.8-9 VEP-NAF-3-A, "Reactor Vessel Fluence Analysis Methodology," Topical Report, Virginia Power, April 1999.

4.8-10 Draft Regulatory Guide DG 1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," September 17, 1999.

4.8-11 WCAP-14040-A, Revision 4, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," May 2004.

4.8-12 Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001.

4.8-13 LTR-SDA-18-049, Revision 0, "Evaluation of Conservatisms and Margins Associated with Surry Units 1 and 2 Reactor Vessel Integrity Extended Beltline Evaluations for Subsequent License Renewal," August 31, 2018.

4.8-14 LTR-REA-18-75, Revision 1, "Surry Extended Beltline Region Reactor Pressure Vessel Materials Fast Neutron Fluence Sensitivity Study on Material Mixture Above and Below the Active Core," August 27, 2018.

4.8-15 ASME Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components."

4.8-16 Regulatory Guide 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” May 1988.

4.8-17 BAW-2324, “Analysis of Capsule X Virginia Power Surry Unit No. 1, Reactor Vessel Material Surveillance Program,” April 1998.

4.8-18 WCAP-16001, Revision 0, “Analysis of Capsule Y from Dominion Surry Unit 2 Reactor Vessel Radiation Surveillance Program,” February 2003.

4.8-19 BAW-2494, Revision 1, “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Surry Units 1 and 2 for Extended Life through 48 Effective Full Power Years,” September 2005.

4.8-20 ANP-3679NP, Revision 0, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80 Years,” June 2018.

4.8-21 ANP-3680NP, Revision 0, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80 Years,” June 2018.

4.8-22 Regulatory Guide 1.161, “Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb,” June 1995.

4.8-23 BAW-2192 (Proprietary), Supplement 1, Rev 0, “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels A & B Service Loads Topical Report,” December 2017.

4.8-24 BAW-2178 (Proprietary), Supplement 1, Rev 0, “Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels C & D Service Loads Topical Report,” December 2017.

4.8-25 ANP-3679P (Proprietary), Revision 0, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80 Years,” June 2018.

4.8-26 ANP-3680P (Proprietary), Revision 0, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80 Years,” June 2018.

4.8-27 PWROG-17090-NP, Revision 0, “Generic Rotterdam Forging and Weld Initial Upper-Shelf Energy Determination,” March 2018.

4.8-28 BAW-2313, Revision 7, Supplement 1, “Supplement to B&W Fabricated Reactor Vessel Materials and Surveillance Data Information for Surry Unit 1 and Unit 2,” February 2017.

4.8-29 BTP-5-3, Revision 2, Branch Technical Position 5-3, “Fracture Toughness Requirements,” March 2007. (ML070850035)

4.8-30 SECY-82-465, “Pressurized Thermal Shock (PTS),” November 23, 1982, Enclosure A. (ML16232A574)

4.8-31 U.S. NRC Regulatory Issue Summary (RIS) 2014-11, “Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components,” October 14, 2014. (ML14149A165)

4.8-32 BAW-2308, Revision 2-A SE, “Final Safety Evaluation for Pressurized Water Reactors Owners Group (PWROG) Topical Report (TR) BAW-2308, Revision 2, ’Initial RT_{NDT} of Linde 80 Weld Materials’”, March 24, 2008

4.8-33 BWRVIP-173-A, “BWR Vessel and Internals Project: Evaluation of Chemistry Data for BWR Vessel Nozzle Forging Materials.”

4.8-34 WCAP-14177, “Surry Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation,” October 1994.

4.8-35 WCAP-18243-NP, Revision 2, “Surry Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation,” July 2018.

4.8-36 TLR-RES/DE/CIB-2013-01, “Evaluation of the Beltline Region for Nuclear Reactor Pressure Vessels, U.S. NRC Technical Letter Report, Office of Nuclear Regulatory Research [RES],” November 14, 2014. (ML14318A177)

4.8-37 ANSI B31.1, “Power Piping, Edition 1955.”

4.8-38 ASME Code, Section VIII, “Rules for Construction of Pressure Vessels.”

4.8-39 WCAP-18341-P (Proprietary), Revision 0, “Resolution of Surry Power Station Units 1 & 2 Time-Limited Aging Analyses for Subsequent License Renewal,” September 2018.

4.8-40 CN-PAFM-16-55, Revision 0, “Transient Basis for Surry Units 1 and 2 80 Year License Renewal Evaluations.”

4.8-41 NRC Letter, “Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding Measurement Uncertainty Recapture Power Uprate (TAC Nos. ME3293 and ME3294),” September 24, 2010. (ML101750002)

4.8-42 NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification,” December 20, 1988. (ML031220290)

4.8-43 WCAP-15607-P (Proprietary), Addendum 3, Revision 0, “Evaluation of Pressurizer Insurge/Outsurge Transients for Surry Subsequent License Renewal - Environmental Assisted Fatigue,” April 2018.

4.8-44 RCC-M, “Design and Construction Rules for the Mechanical Components of PWR Nuclear Islands.”

4.8-45 NRC Letter to Stoddard, “Surry Power Station, Units 1 and 2 - Revised License Renewal Commitment Pressurizer Surge Line Inspection Frequency (EP ID L-2017-LR0-0078),” June 29, 2018. (ML18166A329)

4.8-46 NUREG/CR-6260 (INEL-95/0045), “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,” March 1995. (ML031480219)

4.8-47 EPRI Report 1024995, “Environmentally Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations,” 2012.

4.8-48 SIA 1600274.305, Revision 2, “Selection of Sentinel Locations Based on Environmentally Assisted Fatigue Screening,” September 20, 2018.

4.8-49 SIA Report FP-SPS-401, Revision 1, “Surry Subsequent License Renewal Fatigue Management Accumulation Report,” September 2018.

4.8-50 NUREG/CR-6909 (ANL-12/60), Revision 0, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report,” February 2007. (ML070660620)

4.8-51 NUREG/CR-6909, Revision 1 (Pre-Publication Version), “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials,” March 2018.

4.8-52 NUREG/CR-6909 (ANL-12/60), Draft Revision 1, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials Draft Report for Comment,” March 2014. (ML14087A068)

4.8-53 EPRI Technical Report TR3002000505, Volume 1, Revision 7, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” April 2014.

4.8-54 NRC Bulletin 88-08, Supplement 2, “Thermal Stresses in Piping Connected to Reactor Coolant System,” August 4, 1988. (ML031220144)

4.8-55 ASME 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,” June 23, 2015.

4.8-56 WCAP-18339-P (Proprietary), Revision 0, “Surry Units 1 and 2 ASME Section XI Appendix L Flaw Tolerance Evaluation for Safety Injection, Residual Heat Removal, Pressurizer Spray, Charging and Accumulator Lines,” August 2018.

4.8-57 SIA Report Number 1601007.401 (Proprietary), Revision 0, “Flaw Tolerance Evaluation of the Surry Unit 1 and 2 Hot Leg Surge Line Nozzles Using ASME Code Section XI, Appendix L,” September 2017.

4.8-58 Westinghouse Calculation CN-PAFM-03-46, Revision 1, “Surry 12” Accumulator Nozzle Fatigue Analysis with Environmental Effects,” March 30, 2009.

4.8-59 CN-PAFM-03-47, Revision 1, “Surry 3" Charging Nozzle Fatigue Analysis with Environmental Effects,” March 30, 2009.

4.8-60 NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,” April 1999. (ML031480394)

4.8-61 WCAP-16990-P (Proprietary), Revision 0, “Surry Units 1 and 2 Measurement Uncertainty Recapture Power Uprate Project Engineering Report,” May 2010.

4.8-62 Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment.” (ML080310648)

4.8-63 IEEE Standard 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.” (ML032200206)

4.8-64 11448-EA-62, Revision 0, Add. 00C, “Reactor Containment Liner Fatigue Evaluation for 80-Year Plant Life.”

4.8-65 Crane Manufacturers Association of America Specification 70, 1975.

4.8-66 NUREG-0612, “Control of Heavy Loads at Nuclear power Plants,” July 1980. (ML070250180)

4.8-67 ANSI Standard B30.11-1973, “Monorail Systems and Underhung Cranes.”

4.8-68 ANSI Standard B30.16-1973, “Overhead Hoists.”

4.8-69 ASME Standard HST-4, “Performance Standard for Overhead Electric Wire Rope Hoists.”

4.8-70 Electric Overhead Crane Institute (EOCI) Specification 61 for Electric Overhead Traveling Cranes.

4.8-71 NRC Generic Letter 81-07, “Control of Heavy Loads.”

4.8-72 WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” November 1996.

4.8-73 NRC Letter, “Surry Power Station, Units 1 and 2 - Issuance of Amendments to Extend the Inspection Interval for Reactor Coolant Pump Flywheels (TAC Nos. MC4215 and MC4216),” June 21, 2005. (ML051640591)

4.8-74 WCAP-15666-A, Revision 1, “Extension of Reactor Coolant Pump Motor Flywheel Examination,” October 2003.

4.8-75 PWROG-17011-NP, Revision 1, “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,’” May 2018.

4.8-76 WCAP-15550-P (Proprietary), Revision 1, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 years) Leak-Before-Break Evaluation,” June 2017.

4.8-77 WCAP-15550-NP, Revision 1, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 years) Leak-Before-Break Evaluation,” June 2017.

4.8-78 NUREG/CR-4513, Revision 2, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems,” May 2016. (ML16145A082)

4.8-79 NUREG-0800, Standard Review Plan, Revision 1, Section 3.6.3, “Leak-Before-Break Evaluation Procedures,” March 2007. (ML03600396)

4.8-80 CE-1272, Revision 0, Add. 00B, “Fuel Pool Liner Fatigue Evaluation for 80 Years Plant Life.”

4.8-81 ASME Boiler and Pressure Vessel Code, Section III, Subsections NB-3222.2, NB-3222.4, and NB-3228.5, 2010.

4.8-82 CE-1272, Revision 0, “Analysis of Surry Fuel Pool Liner at 212 Degrees Fahrenheit.”

4.8-83 LTR-PAFM-17-14 Revision 0, “Subject: Surry Units 1 and 2 Piping Subsurface Flaw Evaluation for 80 Years of Service, Subsequent License Renewal,” April 4, 2017.

4.8-84 American Petroleum Institute Standard, API-579-1, “Fitness-For-Service”.

4.8-85 ASME Code Case N-481, “Alternative Examination Requirements for Cast Austenitic Pump Casings, Section XI, Division 1,” March 5, 1990.

4.8-86 WCAP-13045 (Proprietary), “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System,” September 1991.

4.8-87 WCAP-13044 (Proprietary Class 3), “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System,” September 1991.

4.8-88 PWROG-17033-NP, Revision 1, "Update for Subsequent License Renewal: WCAP-13045, ’Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems,’" June 2018.

4.8-89 CN-AMLRS-10-3 (Proprietary), Revision 0, “Implementation of WCAP-16168-NP-A, Revision 2, for Surry Units 1 and 2,” July 29, 2010.

4.8-90 WCAP-15338-A, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants,” October 2002.

4.8-91 PWROG-17031-NP, Revision 1, “Update for Subsequent License Renewal: WCAP-15338-A, A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants,” May 2018.

4.8-92 NRC Bulletin 88-02, “Rapidly Propagating Fatigue Cracks in Steam Generator Tubes,” February 5, 1988. (ML031220043)

4.8-93 Westinghouse Nuclear Safety Advisory Letter (NSAL) 12-7, “Insufficient Insertion of Anti-Vibration Bars in Alloy 600 TT Steam Generators with Quatrefoil Tube Support Plates,” September 24, 2012.

4.8-94 WCAP-18379-P (Proprietary), Revision 0, “Surry Units 1 and 2 Steam Generator U-Bend Tube Vibration and Fatigue Assessment,” July 2018.

4.8-95 Westinghouse Calculation Note, CN-SGDA-02-121, Revision 1, “The Effect of an Uprate to 2609 MWt NSSS Power for Surry Units 1 and 2 on Steam Generator Tube Wear,” October 2008.

4.8-96 Nuclear Energy Institute, NEI 97-06, Revision 3, “Steam Generator Program Guidelines,” January 2011. (ML111310708)

Intentionally Blank

Surry Power Station

Units 1 and 2

Application for Subsequent License Renewal

Appendix A
UFSAR Supplement

Intentionally Blank

List of Tables

List of Figures

NONE

Intentionally Blank

APPENDIX A

A0 INTRODUCTION

This appendix provides the information to be submitted in a Supplement to the Updated Final Safety Analysis Report (UFSAR) as required by 10 CFR 54.21(d) for the Surry Power Station (SPS), Units 1 and 2, 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 UFSAR 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 period of extended operation. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements. Commitments for program additions and 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 period of extended operation. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements. Commitments for program additions and 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 licenses, information currently in the License Renewal section of the UFSAR, 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 UFSAR, future changes to the information in UFSAR 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 non safety-related structures and components (SCs) 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 Dominion OE program interfaces with and relies on active participation in the INPO OE program, as endorsed by the NRC. In accordance with these programs, all incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development 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 Dominion OE program.

A1.1 ASME SECTION XI INSERVICE INSPECTIONS, 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, loss of fracture toughness, and loss of material. The program consists of periodic volumetric, surface, and/or visual examinations and leakage tests of ASME 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 ASME Code, Section XI. The ASME Code, Section XI, edition and addenda used will be consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation. Additional examinations associated with the ASME Code, Section XI, Inservice Inspection program are identified in the Augmented Inspection program, and are included in the ISI Schedule, for the following components:

- Sensitized stainless steel [Class 1, Class 2, and Containment and Recirculation Spray]
- High energy lines outside of Containment [Main Steam and Feedwater lines]
- Component supports [the first seismic restraint beyond the defined ASME functional isolation boundary]
- Steam generator feedwater nozzles [feedwater piping welds from the steam generators to the first elbow.
- Pressurizer instrument connections
- Pressurizer surge line
- MRP-146 thermal stratification inspections

Inspections for three other aspects of the Augmented Inspection program are included in non-ISI programs. Inspections of Reactor Vessel Incore Detector Thimble Tubes are described in the *Flux Thimble Tube Inspection* program (A1.24). Inspections of the Reactor Vessel Head are described in the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program (A1.5). Inspections of the PWR vessel internals are described in the *PWR Vessel Internals* program (A1.7).

A1.2 WATER CHEMISTRY

The *Water Chemistry* program is an existing preventive program that manages loss of material, cracking, 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 Primary Water Chemistry program is consistent with Electric Power Research Institute (EPRI) Report 3002000505, "Pressurized Water Reactor Primary Water Chemistry Guidelines," Revision 7.

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 Secondary Water Chemistry program is consistent with EPRI Report 3002010645, "Pressurized Water Reactor Secondary Water Chemistry Guidelines," Revision 8.

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 (e.g., chloride, fluoride, and sulfate) 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 *One-Time Inspection* program (A1.20) verifies the effectiveness of the *Water Chemistry* program.

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, nuts and washers) and for the threads in the reactor vessel flange.

The *Reactor Head Closure Stud Bolting* 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) within the scope of subsequent license renewal that are susceptible to boric acid corrosion. The program provides for identification of 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 be initiated, and corrective actions can be implemented as necessary. This program includes provisions to initiate evaluations and assessments when leakage is discovered by activities not associated with the program, such as routine plant walkdowns and surveys. When it is determined that an evaluation is necessary, it is performed in a timely manner.

The *Boric Acid Corrosion* program relies in part on NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. The program 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 pressure tests performed in accordance with ASME Code, Section XI, requirements.

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 manages loss of material and 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 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 (A1.2).

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, “Materials Reliability Program: Generic Guidance for Alloy 600 Management”, (MRP-126). Bare-metal visual, surface, and volumetric examinations are used to detect the presence of PWSCC. Inspections are performed periodically.

The nickel-alloy components that are inspected due to susceptibility to PWSCC include the reactor vessel bottom-mounted instrumentation nozzles and J-groove welds (ASME Code Case N-722, as incorporated by reference in 10 CFR 50.55a). Other nickel-alloy components that are inspected, but are resistant to PWSCC, include the reactor vessel head penetration nozzles and 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 corrosion due to boric acid leakage from nearby or adjacent nickel-alloy components previously described.

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 cast austenitic stainless steel reactor coolant pressure boundary components 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.

Aging management of potentially susceptible piping and piping components is accomplished through a component-specific flaw tolerance evaluation in accordance with the ASME Code, Section XI. Based on the completed flaw tolerance evaluation in WCAP-18258, “Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2,” flaw crack growth remains acceptable for the subsequent period of extended operation.

For valve bodies, screening for significance of thermal aging embrittlement is not required. The existing ASME Code, Section XI visual inspection requirements are adequate for valve bodies. The existing ASME Code, Section XI visual inspection requirements are also adequate for managing the aging effects of reactor coolant pump casings because the original flaw tolerance evaluation performed as part of Code Case N-481 remains bounding and is applicable for the subsequent period of extended operation as described in Section A3.7.6.

A1.7 PWR VESSEL INTERNALS

The *PWR Vessel Internals* program is an existing condition monitoring program that manages cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of pre-load 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 1022863, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A),” and EPRI Technical Report 1016609, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals (MRP-228),” to manage the aging effects on the reactor vessel internal components, as supplemented by a gap analysis. The gap analysis includes integration of EPRI Technical Report 3002005349, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines,” (MRP-227, Revision 1), which is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, “Guideline for the Management of Materials Issues”. MRP-227, Revision 1, includes one “mandatory” and four “needed” NEI 03-08 implementation requirements for the *PWR Vessel Internals* program. The guidelines listed in MRP-227, Revision 1, provide an appropriate aging management methodology for the RVI components. The gap analysis also 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”. The inspections of the RVI components are implemented in accordance with EPRI Report 3002005386, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2015 Update (MRP-228, Rev. 2)”.

The Safety Evaluation Report that the NRC issued for the approved version (i.e., MRP-227-A) of MRP-227, Revision 0, dated December 16, 2011, included eight Applicant/Licensee Action Items (A/LAI) that required resolution. Six of those items are applicable for Westinghouse reactors. The six items that require resolution for SPS have been addressed such that no open items exist for the *PWR Vessel Internals* program in preparation for the subsequent period of extended operation.

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 the Virginia Electric and Power Company response to 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 all 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 inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC 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 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 cracking, loss of material, and loss of preload of safety-related and non safety-related closure bolting for pressure-retaining components within the scope of subsequent license renewal.

The program refers to NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants”. NUREG-1339 includes guidance from EPRI report NP-5067, “Good Bolting Practices Volume 1 (Large Bolt Manual),” and from EPRI report NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants”.

The listing for EPRI NP-5769 mentions an exception noted in NUREG-1339 for safety-related bolting. That exception is applicable for bolting used in pressure-retaining applications, and indicates that experimentally–verified fastener material properties and fracture mechanics evaluations should be used to ensure that safety-related fasteners are unlikely to be susceptible to stress corrosion cracking. EPRI Report 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” is applicable for the Bolting Integrity program, and states that applicable material properties should be confirmed with the fastener manufacturer. EPRI Report 1015336 includes guidance for preventing or mitigating stress corrosion cracking by the proper selection of bolting. Table B-1 of EPRI Report 1015336 lists appropriate bolting, and is a reference for the bolting design standard at SPS.

The program includes guidance provided by EPRI reports 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” and 1015337, “Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints,” for assembling bolted connections, and for performing visual examinations of pressure-retaining closure bolting. Preventive measures to preclude or mitigate cracking and loss of preload include proper selections of bolting material and lubricant, and proper application of preload. The absence of high-strength pressure-retaining closure bolting precludes the need for volumetric inspections.

The program addresses management of age-related degradation for applicable submerged bolting, and for piping systems that contain air. Aging management is not required for piping in nitrogen and hydrogen systems due to the absence of in-scope pressure-retaining closure bolting.

The *ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD* program (Section A1.1) includes inspections of closure bolting within the scope of ASME Code, Section XI, and supplements this *Bolting Integrity* program. The following aging management programs for SPS manage aging effects associated with safety-related and non safety-related structural bolting:

- *ASME Section XI, Subsection IWE* program (Section A1.29)
- *ASME Section XI, Subsection IWF* program (Section A1.31)
- *Structures Monitoring* program (Section A1.34)
- *Inspection of Water-Control Structures Associated With Nuclear Power Plants* program (Section A1.35)
- *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program (Section A1.13)

The *External Surfaces Monitoring of Mechanical Components* program (Section A1.23) describes the inspections for non-ASME pressure-retaining bolting.

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 [tubes], plugs, sleeves, 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 the 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. Tube-to-tubesheet welds do not require aging management because the H* alternate repair criteria have been permanently approved to eliminate those hot-leg and cold-leg welds as reactor coolant pressure boundaries.

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 typically are performed every other 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 *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 steam generator, and the subsequent removal of sludge deposits help avoid tube degradation.

The Technical Specifications include the following requirements which are included 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 that exceed acceptance criteria.
- 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 steam generator tube degradation.

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 loss of material, reduction of heat transfer, flow blockage, and cracking, for the piping, piping components, and heat exchangers identified by the Dominion Energy responses to NRC Generic Letter (GL) 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to NRC 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, (c) routine inspection and maintenance so that loss of material, 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 such 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 is performed in accordance with the Virginia Electric and Power Company commitments to GL 89-13 to verify heat transfer capabilities.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (A1.28) will manage the aging effects of internal surface coatings including those of metallic surfaces coated with Carbon Fiber Reinforced Polymer that is used as a pressure boundary.

A1.12 CLOSED TREATED WATER SYSTEMS

The *Closed Treated Water Systems* program is an existing program that manages loss of material, cracking, 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 indications of loss of preload on 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),” ASME B30.11, “Monorail Systems and Underhung Cranes,” and ASME B30.16, “Overhead Hoists (Underhung).”

For those cranes or hoists associated with Time-Limited Aging Analyses, the effects of past and future usage, including the number and magnitude of lifts, are evaluated in Section A3.7.1, Crane Load Cycle Limits.

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 based on the Surry response to NRC GL 88-14, "Instrument Air Supply Problems;" and utilizes 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." 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 signs of loss of material will be performed.

A1.15 FIRE PROTECTION

The *Fire Protection* program is an existing condition and performance monitoring program comprised of functional tests and visual inspections. The program manages:

- loss of material for fire-rated doors, fire damper housings, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- loss of material (spalling) or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- loss of material, change in material properties, cracking/delamination, and separation for non-elastomer fire barrier penetration seals, fire stops, fire wraps, and coatings cracking/delamination, and separation
- loss of material and cracking for aluminum seismic gap covers

This program includes fire barrier inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, fire damper housings, and periodic visual inspection and functional tests of fire-rated doors to demonstrate that their operability is maintained. The program also includes periodic inspections and functional tests of the halon systems and low-pressure carbon dioxide systems.

A1.16 FIRE WATER SYSTEM

The *Fire Water System* program is an existing condition monitoring program that manages loss of material, flow blockage due to fouling, and loss of coating integrity for in-scope water-based fire protection systems. This program manages aging effects by conducting periodic visual inspections, flow testing, and flushes consistent with provisions of the 2011 Edition of National Fire Protection Association (NFPA) 25. Testing of sprinklers that have been in place for 50 years is performed consistent with NFPA 25, 2011 Edition. With exception of two locations, portions of the water-based fire protection system that have been wetted but are normally dry have been confirmed to drain and are not subjected to augmented testing and inspections.

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. 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. Non-code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

A1.17 OUTDOOR AND LARGE ATMOSPHERIC METALLIC STORAGE TANKS

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program is a condition monitoring program that manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), emergency condensate storage tanks (ECSTs), and the emergency condensate makeup tanks (ECMTs). This program also manages aging of the fire protection/domestic water storage tanks (FWSTs) bottom surfaces exposed to soil. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. The RWSTs are insulated and rest on a concrete foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs. The ECSTs and ECMTs are internally coated and protected by concrete missile barriers. Weep holes, located around the circumference of the ECSTs where the concrete missile shield meets the concrete foundation, allow drainage of leakage or condensation to the outside perimeter of the ECSTs. The weep holes will be inspected for water leakage once each refueling cycle. The CATs are skirt supported and insulated with sprayed-on rigid polyurethane foam.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Surface exams of external tank surfaces are conducted to detect cracking on the stainless steel tanks. Inspections of RWST caulking are supplemented with physical manipulation. Thickness measurements of the tanks bottoms are conducted to ensure that significant degradation is not occurring. The external surfaces of insulated tanks are periodically sampling-based inspected. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (A1.28) will manage the internally coated surfaces of the ECSTs and ECMTs. Internal surfaces of the RWSTs and CATs will be managed by the *One-Time Inspection* program (A1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs and ECMTs will be managed by the *Structures Monitoring* program (A1.34).

A1.18 FUEL OIL CHEMISTRY

The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that manages loss of material from 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 are maintained by monitoring and controlling fuel oil contaminants in accordance with Technical Specifications, the Technical Requirements Manual, and ASTM standards. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil.

Fuel oil tanks are periodically drained of water and accumulated sediment, cleaned, and internally inspected when accessible. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks are performed in lieu of cleaning and internal inspection. Tanks that cannot be cleaned and internally inspected, and are physically inaccessible for bottom thickness measurements, are monitored for leakage consistent with the current licensing basis.

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 beltline materials, in accordance with the version of ASTM E-185 available and used during fabrication of the reactor vessels. 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 the 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 Company prior to 10CFR50 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. For the first element, related to the design of the program, WCAP-7723, “Virginia Electric and Power Co. Surry Unit No. 1 Reactor Vessel Radiation Surveillance Program” and WCAP-8085, “Virginia Electric and Power Co. Surry Unit No. 2 Reactor Vessel Radiation Surveillance Program” for Units 1 and 2, documented the program. The *Reactor Vessel Material Surveillance* program for Unit 1 meets either ASTM E 185-66 or ASTM E 185-70. WCAP-8085 states that the Unit 2 *Reactor Vessel Material Surveillance* program meets ASTM E-185-70. Initially, the requirements relating to the testing method was not mandated by the NRC through a particular version of ASTM E185. Therefore, when a capsule was removed from the reactor vessel, it was customary at the time to document which version of ASTM E185 was used for testing. Overtime, the NRC began the process of approving various editions of ASTM E185 for testing. To date, for testing and schedule considerations, the NRC has approved three editions of ASTM E185-73, -79, and -82. Currently, the *Reactor Vessel Material Surveillance* program complies with ASTM E-185-82 for testing and scheduling. Since the withdrawal schedule in Table 1 of ASTM E 185-82 is based on plant operation during the original 40-year initial license term, standby capsules have been incorporated to 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 the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criteria has not been tested previously, then 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 reactor vessel, and is 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 Part 50, Appendix H, all surveillance capsules, including those previously removed from the reactor vessel, 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 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future insertion. 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 reactor vessel components and reactor vessel internal components.

A1.20 ONE-TIME INSPECTION

The *One-Time Inspection* program is a new condition monitoring program that will manage loss of material, cracking, and reduction of heat transfer of components containing reactor coolant, treated borated water, secondary water, fuel oil, or lubricating oil environments.

The *One-Time Inspection* program will conduct one-time inspections of susceptible locations to verify the effectiveness of the *Water Chemistry* program (A1.2), the *Fuel Oil Chemistry* program (A1.18), and *Lubricating Oil Analysis* program (A1.26). 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. 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.

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 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) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the subsequent period of extended operation.

This program 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.

ASME Code components and non-ASME Code components will be inspected using procedures consistent with the ASME Code.

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 or greater than 8% aluminum).

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.

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 are 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 a new condition monitoring program that will manage 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 will utilize volumetric examination techniques demonstrated to be capable of detecting cracking, or destructive examinations to augment the visual examinations (VT-1) required by the ASME Code, Section XI. One-time inspections will determine the presence of cracking for locations within the scope of the ASME Code Class 1 Small-Bore Piping program. With the exception of socket welds for the seal injection line attachments to the reactor coolant pump (RCP) thermal barrier casings at the seal injection nozzles, there is no operating experience of age-related cracking. Therefore, except for those seal injection socket welds, inspection samples will be selected consistent with NUREG-2191 Section XI.M35, Table XI.M35-1, Category A. One-time inspection samples will consist of 3% of the total population in each unit (up to ten maximum) for susceptible butt welds and susceptible socket welds. Each socket weld subject to destructive examination can be credited twice toward the total number of examinations.

For the socket welds on the seal injection lines to the RCP thermal barrier casings, Category B from NUREG-2191, Section XI.M35, Table XI.M35-1 is applicable due to the cracking that occurred in 1998. However, an exception will be taken for the volumetric inspections. As a result of exceedingly limited space in the area of the seal injection line to the thermal barrier casing, a meaningful volumetric examination is not feasible. Volumetric examination could be performed only if the RCP assembly is disassembled for maintenance which could provide for an opportunistic volumetric examination. In lieu of a volumetric examination, a liquid penetrant (LP) examination, that can be performed when sufficient accessibility exists, will provide an acceptable level of information regarding the integrity of the weld. The LP examination for the seal injection line weld at one of the three RCPs will be performed prior to the subsequent period of extended operation. Examinations for the seal injection line welds at the two remaining RCPs will be performed, one per ISI interval, during the subsequent period of extended operation.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.23 EXTERNAL SURFACES MONITORING OF MECHANICAL COMPONENTS

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages 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; 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 stainless steel and aluminum 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 ten years during the subsequent period of extended operation. Following insulation removal, surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect loss of material and cracking of the component surfaces.

Non-ASME Code inspection procedures include 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 (A1.27). 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 forms part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel (RV) where flow-induced fretting causes wear at discontinuities in the path from the RV instrument nozzle to the fuel assembly instrument guide tube. The thimble tube design is a double-walled, asymmetrical configuration to accommodate thermocouple leads located in the annulus between the inner and outer flux thimble tubes. The outer tube is the component that is most susceptible to wear due to its contact with the discontinuities. The inner tube through which the incore detector travels is the reactor coolant system pressure boundary. The double wall design significantly reduces the potential for wear of the inner tube pressure boundary. Periodic eddy current examinations are performed to confirm the integrity of the inner flux thimble tube, and are consistent with the recommendations of NRC Bulletin 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 loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) 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. 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.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel and aluminum components.

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 nineteen components per population at each unit 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.

Inspections are 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 include requirements for items 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 contaminants. Oil testing that indicates the presence of water results in the initiation of corrective action that may include evaluating for in-leakage.

A1.27 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, blistering, and cracking on external surfaces of components in soil or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of steel, stainless steel, copper alloys, fiberglass reinforced plastic, and concrete. Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), 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 electrochemical verification of the effectiveness of CP, nondestructive evaluation of pipe or tank wall thicknesses, performance monitoring of fire mains, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active CP system. Monthly periodic inspections confirm CP system availability and annual CP surveys are conducted to assess the effectiveness of the CP system. For steel components, the CP effectiveness acceptance criterion is -850 mV instant off.

The balance of piping and tanks within the scope of subsequent license renewal are not provided with CP. Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of subsequent license renewal is not corrosive 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, the sample size is increased.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (A1.16).

A1.28 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 an existing condition monitoring program that manages loss of coating integrity of the internal coatings/linings of the in-scope components, exposed to closed-cycle cooling water, raw water, treated water, treated borated water, and waste 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.

Periodic visual inspections are conducted of each coating/lining material and environment combinations applied to the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s).

For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sample-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, “Service Level I, II and II Protective Coatings Applied to Nuclear Power Plants,” including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. 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. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.

A1.29 ASME SECTION XI, SUBSECTION IWE

The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that manages cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness. 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.

This program also includes surface examination for the detection of cracking of structural bolting. In addition, the program includes supplemental surface or enhanced examinations to detect cracking for specific pressure-retaining components. Containment penetrations were not analyzed for cyclic fatigue and will require surface examinations in addition to visual examinations to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading. 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. Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side. 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 Code specified 12 months before the start of the inspection interval.

A1.30 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:

- Cracking
- Cracking; Loss of material
- Cracking and distortion
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking

Qualified inspectors identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, evaluations are performed which consider the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (A1.30), the *Structures Monitoring* program (A1.34), or the *Inspection of Water-Control Structures Associated With Nuclear Power Plants* program (A1.35).

The design of the reinforced concrete containment does not utilize prestressing tendons. 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-02.

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 Code specified 12 months before the start of the inspection interval.

A1.31 ASME SECTION XI, SUBSECTION IWF

The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that manages loss of material, cracking, loss of preload, and loss of mechanical function for supports of Class 1, 2, and 3 components. There are no Class MC supports at SPS. 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. For high-strength bolting with an actual yield strength equal to or greater than 150 ksi in sizes greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 are performed to detect cracking in addition to the VT-3 examination. If a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

A1.32 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; Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program;” and NEI 94-01, “Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J”.

A1.33 MASONRY WALLS

The *Masonry Walls* program is an existing condition monitoring program that is implemented as part of the *Structures Monitoring* program (A1.34) and manages loss of material, cracking, and loss of material (spalling and scaling) that could impact the intended function of the masonry walls.

The *Masonry Walls* program consists of inspections, consistent with Inspection and Enforcement Bulletin (IEB) 80-11 and plant-specific monitoring proposed by Information Notice (IN) 87-67, for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained. The inspections of the masonry walls within the scope of subsequent license renewal are conducted by qualified personnel at a frequency not to exceed five years.

A1.34 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 material
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Loss of material
- Loss of material, change in material properties
- 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-02, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” The inspection of structural components, including masonry walls and water-control structures, are performed at intervals not to exceed five years, except for wooden poles, which are inspected on a 10-year frequency.

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 *Structures Monitoring* program (A1.34), the *ASME Section XI, Subsection IWL* program (A1.30), or the *Inspection of Water-Control Structures Associated With Nuclear Power Plants* program (A1.35).

A1.35 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 is implemented as part of the *Structures Monitoring* program (A1.34), and manages the following aging effects:

- Cracking
- Cracking; blistering
- Cracking; blistering; loss of material
- 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

This program consists of inspection and surveillance of raw-water control structures associated with emergency cooling systems or flood protection, which are the Discharge Canal, Intake Canal, Discharge Tunnel and Seal Pit, High Level Intake Structure, and the Low Level Intake Structure. The program also includes structural steel 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 are 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 by qualified personnel at a frequency not to exceed five years. 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, inaccessible areas are assessed for aging and opportunistically inspected when excavated. Plant operating experience has not identified any structural degradation due to aggressive water chemistry.

A1.36 PROTECTIVE COATING MONITORING AND MAINTENANCE

The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. The program manages coating system selection, application, visual inspections, assessments, repairs, and maintenance of Service Level I protective coatings as defined in RG 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants”.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside Containment (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, but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liner and components. 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 amount of unqualified coatings. Unqualified coating may fail in a way to affect 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 primary containment is kept within acceptable design limits to support the post-accident operability of the ECCS.

A1.37 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 insulation material subject to an adverse localized environment.

The program performs a plant walkdown of in-scope structures to visually inspect for accessible cables and connections located in an adverse localized environment. If an adverse localized environment is observed, accessible electrical cables and connections installed within that environment will be 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.

Additionally, visual inspection findings may necessitate testing. Should testing be deemed necessary based on the unacceptable visual indications of surface anomalies, 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. Testing as part of an existing maintenance, calibration or surveillance program may be credited. 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 at least once every ten years.

A1.38 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) insulation material subject to sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

The program applies to the containment high range radiation monitor system, the post-accident neutron monitoring system, and the excore neutron monitoring system.

The containment high range radiation monitor system cables are connected during calibration. Therefore, the calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation material aging degradation. The reviews are completed prior to the subsequent period of extended operation and at least every ten years thereafter.

The excore neutron monitoring system cables are disconnected during calibration. The program performs a proven cable test for detecting deterioration of the cable system insulation material. The test frequency is based on engineering evaluation and is performed at least once every ten years.

The post-accident neutron monitoring system cables are disconnected during calibration. The program will perform a proven cable test for detecting deterioration of the cable system insulation material. The tests will be completed prior to the subsequent period of extended operation and at least every ten years thereafter.

A1.39 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 of inaccessible medium-voltage cables (operating voltages of 2kV to 35kV) exposed to significant moisture.

The program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ medium-voltage power 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 ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. This inspection and water removal is performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding).

In-scope non-EQ inaccessible medium-voltage power cables routed through manholes and duct banks are tested to detect reduced electrical insulation resistance 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.

There are no submarine cables or other cables designed for continuous wetting or submergence currently in the scope of this program. Future installed cables of this design would be considered for inclusion in this program.

A1.40 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 leading to electrical failure of in-scope non-EQ inaccessible instrument and control cables.

This program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ instrument and control cable, within the scope of subsequent license renewal that are 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.

Periodic actions will be taken to prevent inaccessible instrument and control cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. This inspection and water removal will be performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding).

Inaccessible instrument and control cables that are exposed to significant moisture, or are found to be degraded during a periodic inspection, are evaluated to determine if testing is required. If testing is required, the cables will be tested using one or more proven tests for detecting reduced insulation resistance.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.41 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 of inaccessible low-voltage power (operating voltage less than 2kV) cables exposed to significant moisture.

The program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ low-voltage power cables, within the scope of subsequent license renewal that are 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.

Periodic actions will be taken to prevent inaccessible low-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. This inspection and water removal will be performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding).

Inaccessible low-voltage power cables that are exposed to significant moisture, or are found to be degraded during a periodic inspection, are evaluated to determine if testing is required. If testing is required, the cables will be tested using one or more proven tests for detecting reduced insulation resistance.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.42 METAL ENCLOSED BUS

The *Metal Enclosed Bus* program is an existing condition monitoring program that manages the aging effect of degradation of electrical insulating material, reduced electrical insulation resistance, cracking, and loss of continuity or increased contact resistance of the bolted connections for metal enclosed bus (MEB) and internal components. Bus enclosure assemblies (internal and external), bus bar insulation, bus bar insulating supports, and bus bar bolted connections are included.

Visual inspection of accessible metal enclosed bus internal surfaces is performed to detect age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. Accessible metal enclosed bus insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, swelling, discoloration, or surface contamination, which may indicate overheating or aging degradations. The accessible internal bus insulating supports are visually inspected for structural integrity and signs of cracks. Accessible metal enclosed bus external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion.

Accessible elastomers (e.g., gaskets, boots, and sealants) are inspected for degradation, including surface cracking, crazing, scuffing, and changes in dimensions (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening and loss of strength. A sample of accessible bolted connections is inspected for increased resistance of connection by measuring connection resistance using a micro-ohmmeter.

The first inspection, including measuring connection resistance, is completed prior to the subsequent period of extended operation and at least every twelve years thereafter for emergency buses and every ten years thereafter for non-emergency buses, with the exception of MEB associated with transfer bus F. If internal inspections of metal enclosed bus associated with either transfer bus D or E identify degradation that would result in a loss of intended function, MEB associated with transfer bus F will be scheduled for inspection and testing. An opportunistic inspection of MEB associated with transfer bus F will also be performed if a dual unit outage of at least ten days duration occurs and transfer bus F can be deenergized without a significant safety impact to the units.

A1.43 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 electrical cable connections (metallic parts).

This program will perform a one-time inspection, 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: application (medium and low voltage), circuit loading (high load), connection type, 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 cables 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, or insulating boots, etc.

Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting components under test will be included as part of the program's documentation.

A 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 license renewal are to 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 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.

A1.44 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 high-voltage insulators that are credited for recovery of offsite power.

High Voltage insulator surfaces will be visually inspected to detect reduced electrical insulation resistance aging effects including cracks, foreign debris, excessive salt, dust, fog, and industrial effluent contamination. Metallic parts of the insulator will be visually inspected to detect loss of material due to mechanical wear or corrosion.

The high-voltage 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. For high-voltage insulators that are coated, the visual inspection will be performed at least once every five years.

The first inspections will be completed prior to the subsequent period of extended operation.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A2 SUMMARY DESCRIPTIONS OF TIME-LIMITED AGING ANALYSIS AGING MANAGEMENT PROGRAMS

A2.1 FATIGUE MONITORING

The *Fatigue Monitoring* program is an existing preventive program that manages cycle-based 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 accept 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, including those in applicable cumulative usage factor (CUF) analyses, environmental-assisted fatigue analyses (CUF_{en} analyses), maximum allowable stress range reduction/expansion stress analyses for ANSI B31.1 and ASME Code Class 2 and 3 components, ASME III fatigue waiver analyses, and cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses.

The program manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the applicable structures and components through performance of activities that monitor one or more relevant analysis parameters, such as CUF values, CUF_{en} values, design transient cycle limit values, or predicted flaw size values. The program also sets applicable acceptance criteria (limits) on these parameters. Therefore, the program has two aspects, one to verify the continued acceptability of existing analyses through cycle counting or parameter monitoring and the other to provide periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits.

The program also implements appropriate corrective actions (e.g., reanalysis, component or structure inspections, or component or structure repair or replacement activities) when acceptance limits are approached.

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>1MeV) 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 RPVs, the monitoring methods are performed in a manner that is consistent with the monitoring methodology guidelines in Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." Neutron fluence monitoring methods that are applied to RPV locations outside of the beltline region of the RPVs were justified and are consistent with NRC-approved methodology.

This program's results are compared to the neutron fluence parameter inputs used in the 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 low temperature overpressure protection (LTOP) 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 RPVs 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) includes those for $RT_{NDT.}$

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the *Reactor Vessel Material Surveillance* program (A1.19) provides inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 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 Electrical 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 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform applicable safety functions in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of 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 Electrical Equipment* program is consistent with the guidance of 10 CFR 50.49; Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment”; “Guidelines for Evaluation of Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors” (DOR Guidelines); 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.

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

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.

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 (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)

A3.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

10 CFR 50.60 requires that all light water reactors meet the fracture toughness, 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
- Upper-Shelf Energy
- Pressurized Thermal Shock
- Adjusted Reference Temperature
- Pressure Temperature Limits
- Low Temperature Overpressure Protection

A3.2.1 Neutron Fluence Projections

Updated neutron fluence evaluations were performed and documented in WCAP-18028-NP, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Power Station Units 1 & 2.” RPV beltline and extended beltline fast neutron fluences (E > 1.0 MeV) at the end of 80 years of operation were calculated for Units 1 and 2. The analyses methodologies used to calculate the Units 1 and 2 RPV 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-14040, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” and are documented in UFSAR Section 4.1.7.3, “Calculation of Integrated Fast Neutron (E Greater than 1.0 MeV) Flux at the Irradiation Samples.” 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).

A3.2.2 Upper-Shelf Energy

Appendix G of 10 CFR 50 (Reference 4.2-13), Paragraph IV.A.1.a, indicates that reactor pressure vessel (RPV) beltline materials must have Charpy upper-shelf energy of no less than 75 ft-lb initially, and must maintain Charpy upper-shelf energy 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 upper-shelf energy 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 Protection Against Failure” (Reference 4.2-14). For materials outside the beltline, a minimum value of 30 ft-lbs at 10 °F was specified by ASTM E208 at the time of the initial design of Units 1 and 2. The upper shelf energy (USE) analyses for the ferritic steel components (i.e., RPV shell plates or forgings, nozzle plates or forgings, and associated pressure retaining welds) in the beltline region of the RPV 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 RPV surveillance test data for the facility. Based on WCAP-18242-NP, *Surry Power Station Units 1 and 2 Time Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal*, the materials that exceeded the 1.0×10^{17} n/cm^2 (E > 1.0 MeV) threshold at 68 EFPY are considered to be the Units 1 and 2 extended beltline materials and were evaluated to determine their impact on the subsequent period of extended operation. The forgings and welds corresponding to the Units 1 and 2 Inlet Nozzles 1, Inlet Nozzles 3, and Outlet Nozzles 3 are predicted to experience neutron fluence greater than 1.0×10^{17} n/cm^2 at the end of the period of extended operation. However, for conservatism all of the Units 1 and 2 inlet and outlet nozzle materials are considered part of the extended beltline.

For Unit 1, the limiting USE value at 68 EFPY is 32 ft-lb; this value corresponds to the Intermediate to Lower Shell Circumferential Weld (Heat # 72445). For Unit 2, the limiting USE value at 68 EFPY is 41 ft-lb; this value corresponds to the Upper to Intermediate Shell Circumferential Weld (Heat # 4275).

The NRC has previously approved the use of the equivalent margins analysis (EMA) BAW-2494, *Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Surry Power Station Units 1 and 2 for Extended Life through 48 Effective Full Power Years* to qualify all of the materials currently projected to drop below 50 ft-lb USE at 68 EFPY. The EMAs for these materials are updated for the subsequent period of extended operation under ANP-3679NP, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80 Years” and ANP-3680NP, “Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80 Years” The updated EMA is based upon the provisions outlined in NRC Regulatory Guide 1.161 and Section XI of the ASME Code, Appendix K. The EMAs were submitted with the subsequent license renewal application.

The following Units 1 and 2 materials are addressed by EMAs in ANP-3679NP and ANP-3680NP for the subsequent period of extended operation:

Unit 1:

- Upper to Intermediate Shell Circumferential Weld, Heat # 25017 (J726)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 8T1554
- Intermediate to Lower Shell Circumferential Weld, Heat # 72445
- Lower Shell Longitudinal Weld L1, Heat # 8T1554
- Lower Shell Longitudinal Weld L2, Heat # 299L44
- Inlet Nozzle to Shell Welds, Heat # 299L44 and # 8T1762; (Projected USE > 50 ft-lbs at 68 EFPY)
- Outlet Nozzle to Shell Welds, Heat # 8T1762 and # 8T1554B; (Projected USE > 50 ft-lbs at 68 EFPY)

Unit 2:

- Upper to Intermediate Shell Circumferential Weld, Heat # 4275 (J737)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 72445
- Intermediate Shell Longitudinal Weld L4, Heat # 8T1762
- Intermediate to Lower Shell Circumferential Weld, Heat # 0227
- Lower Shell Longitudinal Weld L1 and L2, Heat # 8T1762
- Inlet Nozzle to Shell Welds, Heat # 8T1762; (Projected USE not projected > 50 ft-lbs at 68 EFPY)
- Outlet Nozzle to Shell Welds, Rotterdam Weld; (Projected USE > 50 ft-lbs at 68 EFPY)

Note that as a conservative measure, an EMA has been completed for Units 1 and 2 Inlet and Outlet Nozzle to Shell Welds even though these materials are not projected to drop below 50 ft-lbs through 68 EFPY. The inlet and outlet nozzle welds are the only materials included in ANP-3679NP and ANP-3680NP that were not previously addressed by EMA. The EMA is applicable to Units 1 and 2 nozzle to shell welds which exceed the fluence criterion of 1.0×10^{17} n/cm^2 before 68 EFPY. These materials include those listed below.

- Unit 1 Outlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 3 to Upper Shell Weld
- Unit 2 Outlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 3 to Upper Shell Weld

For Unit 1, the limiting USE value for materials not requiring an EMA at 68 EFPY is 54 ft-lb; this value corresponds to the Inlet Nozzle to Upper Shell Welds (Heat # 299L44). For Unit 2, the limiting

USE value for materials not requiring an EMA at 68 EFPY is also 54 ft-lb; this value corresponds to the Outlet Nozzle to Upper Shell Welds (Rotterdam). Except for the materials listed above, all of the beltline and extended beltline materials in Units 1 and 2 RPVs are projected to remain above the USE screening criterion value of 50 ft-lb (per 10 CFR 50, Appendix G) through the subsequent period of extended operation (68 EFPY).

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 reactor pressure vessel (RPV) beltline materials to be less than the PTS screening criteria at the expiration date of the operating license unless otherwise approved by the NRC. All of the beltline and extended beltline materials in the Units 1 and 2 RPV 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 68 EFPY. 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 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-16045-NP. The limiting ART values at 48 EFPY and 68 EFPY are less than the limiting ART values used to develop the existing P-T limit curves. The ART analyses have been projected to the end of the 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 RPV 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 RPV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RPV 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 license renewal 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 the Technical Specifications. The P-T limit curves for normal heatup and cooldown of the primary reactor coolant system for Units 1 and 2 were previously developed in WCAP-14177.

The *Reactor Vessel Material Surveillance* program (A1.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the current terms of applicability for Units 1 and 2. Since the P-T limits will be updated through 10 CFR 50.90 at a later, appropriate date, the effects of aging on the intended function(s) of the RPVs will be adequately managed for the 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 Units 1 and 2 low temperature overpressure protection (LTOP) system is required by Technical Specification Limited Condition for Operation 3.1.G. Two pressurizer power operated relief valves (PORV) are used to provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the reactor coolant system pressure from exceeding the pressure temperature limit curves based on 10 CFR 50, Appendix G.

The LTOP enabling temperature has been determined for 68 EFPY. Using Code Case N-514, the LTOP enabling temperature is 283°F. Using Code Case N-641, the LTOP enabling temperature can be either 273°F or 262°F. The Surry Technical Specification 3.1.G.1.c.(4) specifies an arming temperature of 350°F which is conservative and remains valid for the subsequent period of extended operation.

In WCAP-18242-NP, “Surry Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal,” the maximum allowable Low Temperature Overpressure Protection System (LTOPS) pressurizer PORV setpoint was calculated to be 399.6 psig for the subsequent period of extended operation. The calculation was performed in accordance with the WCAP-14040-A, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit,” methodology using critical LTOPS input parameters and the limiting axial flaw steady state Appendix G limits calculated for 68 EFPY. The evaluation showed that the current Technical Specification value of ≤ 390.0 psig is bounding and will remain valid for the subsequent period of extended operation.

The LTOP system licensing and design basis 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).

A3.3 METAL FATIGUE

Fatigue analyses are required on components designed to ASME Code, Section III, Class 1. Also, certain other codes such as ASME Code, Section III, Class 2 and 3, USAS (ANSI) B31.1, and ASME Code, Section VIII, Division 2, may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. NUREG-2192 also provides examples of components that are likely to have fatigue TLAAs within the current licensing basis (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 current licensing bases for Units 1 and 2. Each of the potential TLAAs were evaluated against the six TLAA screening criteria specified in 10 CFR 54.3. Those that were identified as fatigue TLAAs are evaluated in the following Subsections:

- Transient Cycle Projections for 80 years (Section A3.3.1)
- ASME Code, Section III, Class 1 Fatigue Analyses (Section A3.3.2)
- ANSI B31.1 Allowable Stress Analyses (Section A3.3.3)
- Environmental- Assisted Fatigue (Section A3.3.4)
- Reactor Vessel Internals Fatigue 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. UFSAR Table 4.1-8 and Section 18.4.2 provides a listing of 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 are postulated to bound 60 years of service. Since the fatigue analyses are based upon a number of cycles postulated to bound sixty years of service for the current license basis, these analyses constitute a TLAA.

Baseline cycle counts were projected to an 80-year operating life based on the actual accumulation history over the 10-year period from June 30, 2006 to June 30, 2016. Since most nuclear power plants, including SPS Units 1 and 2, have experienced a significant declining trend in accumulation of transients over time, transient projections based on recent operating experience provide an appropriate basis for future projections. Therefore, each monitored design transient was evaluated to determine if the recent 10-year trend had a consistent cycle accumulation rate. The 10-year rate was used to extrapolate the projected number of future occurrences beginning June 30, 2016 and ending at 80 years of plant operation. The end of 80-year life is June 2052 for Unit 1 and March 2053 for Unit 2. The projected cycles for 80 years of plant operation were less than the 40-year design cycles (CLB cycles) used in the fatigue analyses. Therefore, the fatigue analyses for ASME

Code, Section III components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the ASME Code, Section III fatigue analyses, the Fatigue Monitoring program (B3.1) will track cycles for significant fatigue transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits. A Condition Report will be initiated based upon an administrative limit of 90% of the fatigue cycles.

A3.3.2 ASME Code, Section III, Class 1 Fatigue Analyses

Fatigue analyses are performed per ASME Code, Section III. Each analysis is required to demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the Code design limit 1.0 when the component is exposed to all postulated transients.

The following ASME Code, Section III components were assessed for impact on fatigue:

- Control Rod Drive Mechanism (CRDM)
- Pressurizer
- Reactor Coolant Pump
- Reactor Vessel
- Steam Generator
- Pressurizer Surge Line
- Charging and Accumulator Piping

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 40-year design cycles (CLB cycles) were postulated to bound 80 years of plant operations. Therefore, the fatigue analyses and fatigue waivers remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the fatigue analyses and fatigue waivers, the *Fatigue Monitoring* program (Section A2.1) will track cycles for significant fatigue transients listed in the UFSAR, Table 4.1-8 and Section 18.4.2, and ensure 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 components will be adequately managed by the *Fatigue Monitoring* program (Section A2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A3.3.3 ANSI B31.1 Allowable Stress Analyses

The reactor coolant system's primary loop piping and the balance-of-plant piping in scope for subsequent license renewal are analyzed to the requirements of ANSI B31.1, "Power Piping." There are two aspects of note that pertain to fatigue for the ANSI B31.1 piping. The first aspect is discussed below and is related to the design of the piping which does not utilize fatigue usage factors. The second aspect deals with the concern of environmental effect which is discussed in Section A3.3.4.

For piping systems designed in accordance with ANSI B31.1, 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 ANSI B31.1, 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.

ANSI B31.1 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 piping systems designed in accordance with ANSI B31.1 requirements 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 generator nitrogen, main steam, blowdown, feedwater, condensate, chemical and volume control, extraction steam, residual heat removal, and safety injection. 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. For example, residual heat removal system cycles twice per shutdown/start up and therefore has fewer cycles than the residual heat removal system piping at the boundary with the reactor coolant system. The expected transients for these systems are much less than 7,000 cycles for 80 years of plant operation.

Portions of the following systems, designed in accordance with ANSI B31.1 requirements, are affected by thermal and pressure transients that are different than the reactor coolant and power cycles discussed above: auxiliary steam, boron recovery, containment vacuum and leakage monitoring, emergency diesel generator (engine exhaust), alternate AC diesel generator (engine exhaust), security diesel (engine exhaust), fire protection (fire pump diesel exhaust), heating steam, recirculation spray, sampling system, and steam drains. The basis for cycle projections have been reviewed for these systems to validate that the projected cycles for 80 years of operation remains 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 ANSI B31.1 allowable stress analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21 (c)(1)(i).

A3.3.4 Environmental- Assisted Fatigue

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on cumulative usage factor (CUF) must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. Additional limiting locations were identified through an environmental fatigue screening evaluation. The environmentally-assisted fatigue (EAF) screening evaluation reviewed the CLB fatigue evaluations for all ASME Code, Section III reactor coolant pressure boundary components and ANSI B31.1 piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

The sentinel locations are listed below:

- CRDM head adapters (J-groove weld) - replacement RV closure heads
- RV outlet nozzles and support pads (NUREG/CR-6260 location)
- RV inlet nozzles (NUREG/CR-6260 location)
- RV bottom head-to-shell juncture (NUREG/CR-6260 location)
- CRDM upper latch housing and rod travel housing – upper latch housing
- CRDM upper joint – Canopy
- Pressurizer spray nozzle
- Pressurizer spray nozzle – Piping
- Pressurizer
- Upper shell
- Pressurizer Safety and Relief nozzles
- Pressurizer lower head at heater penetration
- Hot leg surge nozzle - bounding location (NUREG/CR-6260 location)
- Pressurizer surge piping

- Pressurizer surge nozzle to safe end weld
- Charging nozzle (NUREG/CR-6260 location)
- Safety injection nozzle (NUREG/CR-6260 location)
- Residual heat removal piping (NUREG/CR-6260 location)
- Steam generator tubes
- Accumulator piping NUREG/CR-6260 location)

For sentinel ASME Code, Section III components with environmentally-assisted fatigue usage (CUF_{en}) greater than 1.0, ASME Code, Section III, NB-3200 calculations were prepared to remove conservatisms used in the analysis of record, thereby reducing the CUF_{en} to less than 1.0. The effects of fatigue on the intended functions of these ASME Code, Section III components will be managed by the *Fatigue Monitoring* program (Section A2.1) through the use of cycle counting.

For sentinel piping locations, Dominion has elected to manage the effects of fatigue by application of the *ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD* program (Section A1.1) during the subsequent period of extended operation based on results of flaw tolerance evaluation conducted per the guidance of ASME Code, Section XI, Non-mandatory Appendix L. 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 evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location. For a postulated initial flaw, crack growth is simulated until the flaw has reached the allowable flaw depth or the end of the subsequent period of extended operation, whichever comes first.

in-service inspections of the Appendix L piping will be performed at a 10-year inspection frequency. Each weld in the inspection population will be ultrasonically inspected once prior to turning on the clock for the re-inspection schedule associated with the Appendix L evaluations. Going forward after the first ultrasonic inspection, one weld in each of the six groups will be ultrasonically inspected every ten years.

Fatigue of the steam generator tubes will be managed by the *Steam Generators* program (Section A1.10).

The effects of fatigue on the intended functions of ASME Code, Section III components and piping that contact reactor coolant will be managed by the *Fatigue Monitoring* program (Section A2.1), the *ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD* program (Section A1.1) and the *Steam Generators* program (Section A1.10) through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A3.3.5 Reactor Vessel Internals Fatigue Analyses

The RV internals were designed before ASME Code, Section III, Division 1, Subsection NG was established. Therefore, no CUF values were calculated as part of the original RV internals design. However, as part of engineering evaluations to support Units 1 and 2 operations at MUR power uprate conditions, updated structural evaluations were performed for the upper and lower core plates to demonstrate that they would maintain their structural integrity at proposed power uprate conditions. The lower and upper core plates are not part of the reactor coolant system pressure boundary. As part of the structural evaluations, fatigue analyses of the upper and lower core plates were performed to the 1989 edition of ASME Code, Section III, Division 1, Subsection NG. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The analysis of record fatigue CUF results are less than 1.0.

The 40-year design cycles (CLB cycles) were postulated to bound 80 years of plant operations. Therefore, the reactor vessel internals fatigue analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A3.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

Thermal, radiation, and cyclical aging analyses of plant 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 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.

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.

The EQ program was evaluated against the DOR Guidelines and the basis for equipment qualification is Inspection and Enforcement Bulletin (IEB) 79-01B (IEB 79-01B), “Environmental Qualification of Class 1E Equipment,” and IEEE Standard 323-1974, “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 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

Not applicable

A3.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE ANALYSIS

A3.6.1 Containment Liner Plate

The accumulated fatigue effects of all applicable liner loading conditions are evaluated based on cycles of operating pressure variations, cycles of operating temperature variations, and design earthquake cycles. The anticipated operating pressure variations were extrapolated for 80 years of operation and determined to be acceptable. The number of design cycles was conservatively increased to account for the subsequent period of extended operation. Therefore, the Containment liner is adequate for an 80-year operating period as currently designed. The analyses associated with the Containment liner plate have been revised and projected to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

A3.6.2 Metal Containments

Not applicable

A3.6.3 Containment Penetrations Fatigue Analysis

There are no TLAAs for Containment penetrations. The penetrations are designed for a one-time load, which is equal to the collapse loads of the pipe. The stresses due to the normal operating conditions are within the endurance limit. Therefore, the penetrations will not fail for a large number of operating cycles. No time-limited aging analysis has been performed for the penetrations.

A3.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

A3.7.1 Crane Load Cycle Limits

The design standard number of full-capacity lifts far exceeds the number expected of each machine for a 80-year life, even with a significant number of unforeseen lifts. The lifting machine designs therefore remain valid for the period of extended operation. These TLAAs 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,” Revision 0,” which confirms that the analysis of WCAP-14535A and WCAP-15666-A remains appropriate. The fatigue crack growth calculations assumed 6000 cycles of RCP start/stop for 80 years of plant life which bounds the projected cycle count of 1158. The RCP fatigue analysis remains valid for the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.3 Leak-Before-Break

10 CFR 50 General Design Criterion 4 allows use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in PWRs. WCAP-15550-NP, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation,” demonstrated compliance with leak-before-break (LBB) technology for the reactor coolant system piping for an 80-year plant life based on a plant specific analysis that showed all LBB conditions and margins are satisfied. It is therefore concluded that dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis. The LBB analysis has been projected to the end of the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.4 Spent Fuel Pool Liner Fatigue Analysis

A design calculation has been identified which documents that the spent fuel pool liner design meets general industry criteria. A revised calculation includes a fatigue analysis based on the number of thermal cycles corresponding to an 80-year plant operating term. The thermal stresses in the spent fuel pool liner due to conservatively assumed temperature gradients and thermal cycles during an 80-year plant operating term satisfy ASME Code fatigue criteria. Therefore, the revised calculations are projected through the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.5 Piping Subsurface Flaw Evaluations

Piping subsurface flaws were detected during original plant construction. Flaw tolerance conclusions of the piping subsurface flaws evaluations have been projected to the end of the subsequent period of extended operation. The piping flaw TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.6 Reactor Coolant Pump Code Case N-481

ASME Code Case N-481 allows the replacement of volumetric examinations of primary loop pump casings with fracture mechanics-based integrity evaluations supplemented by specific visual examinations. The fracture mechanics integrity assessment in PWROG-17033 -NP, “Update for Subsequent License Renewal: WCAP-13045, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems,” Revision 0,” which updated the analysis in WCAP-13045, demonstrated that the visual inspections, in lieu of volumetric inspections, for pump casings remain valid for an 80-year life and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.7 Cracking Associated With Weld Deposited Cladding

Reactor vessel underclad cracking involves cracks in base metal forgings immediately beneath austenitic stainless steel cladding which are created as a result of the weld-deposited cladding process. PWROG-17031-NP, “Update for Subsequent License Renewal: WCAP-15338-A, “A Review of Cracking Associated with Weld Deposited Cracking in Operating PWR Plants,” Revision 0,” updated the 60-year fatigue crack growth analysis in WCAP-15338-A and confirmed the analysis remains appropriate for 80 years of operation. The crack growth analysis has been projected to the end of the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.8 Steam Generator Tube High Cycle Fatigue Evaluation

WCAP-18379-P, "Surry Units 1 and 2 Steam Generator U-Bend Tube Vibration and Fatigue Assessment" evaluated the SG tubes that are unsupported by an AVB which is contrary to the design requirements, or tubes that are subject to significant flow peaking due to non-uniform insertion of the AVBs, to determine if they are subject to possible fatigue related failure during the planed 80 years of plant life.

The new fatigue analysis demonstrates that all unsupported tubes are acceptable without remediation through 80 years. This evaluation is projected through the subsequent period of extended operation and this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.9 Steam Generator Tube Wear Evaluation

WCAP-18341-P, "Resolution of Surry Power Station Units 1 & 2 Time-Limited Aging Analyses for Subsequent License Renewal," shows that for the increase the operating term from 60 years to 80 years, the calculated tube wear remains acceptable. The steam generator tube wear will be managed by the *Steam Generators* program (A1.10) using the existing steam generator eddy current inspection consistent with NEI 97-06, "Steam Generator Program Guidelines"

The wear evaluation for operation under MUR power uprate conditions demonstrates wear of the steam generator tubes will be acceptable through 80 years of plant operation. The steam generator tube wear will be managed by the *Steam Generators* program (A1.10) in accordance with 10 CFR 54.21(c)(iii).

Intentionally Blank

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 inspections be performed for welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix L for the following auxiliary lines: • Safety injection • Residual heat removal • Spray • Charging • Accumulator • Surge	B2.1.1	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
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. 2. Procedures will be revised to require the performance of a one-time visual inspection of the bottom plates in Unit 2 vessel flange closure stud holes #36 and #37 to confirm that no corrosion, cracking, or degradation is occurring.	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

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
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
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

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	The *PWR Vessel Internals* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised for each reload to summarize the average power density, the heat generation figure-of-merit, and the dimensional parameter for the distance between the active fuel and the upper core plate. 2. Procedures will be revised to require the visual inspection (EVT-1) of the control rod guide tube (CRGT) lower flange weld to require that the inspection include 100% of the outer CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal. 3. Procedures will be revised to require the visual inspection (VT-3) of the accessible surfaces for the control rod guide tube support pins and support pin nuts for Unit 1 only (plant-specific component). 4. Procedures will be revised to require the addition of a note indicating that a bolting inspection can be credited only if at least 75% of the total bolt population is examined. 5. Procedures will be revised to require visual inspection (VT-3) for 100% of the baffle-edge bolts that are accessible from the core side. 6. Procedures will be revised to require volumetric (UT) examinations for 100% of accessible baffle-former bolts (including corner bolts) at least every 10 years. MRP-2017-009 states that baseline volumetric (UT) examinations shall be performed no later than 30 EFPY for NSAL 16-1 Tier 2 plants, including the Surry units. The guidance further states that initial baseline UT exams performed prior to 1/1/2018 are acceptable. Examinations were performed in 2010 for Unit 1 and in 2011 for Unit 2. For the Surry units with the down-flow configuration that have <3% indications and no clustering, subsequent UT examinations are performed on a 10-year interval. 7. Procedures will be revised to address expansion criteria when degradation occurs for clusters of baffle-former bolts. MRP 2018-002 identifies expansion criteria as a Needed requirement (per NEI 03-08) to include one-time visual (VT-3) examination of barrel-former bolts if large clusters of baffle-former bolts are found during the initial volumetric (UT) examination. 8. Procedures will be revised to require visual examinations (EVT-1) for 100% of one side (ID or OD) of the circumference for the core barrel upper flange weld, and ¾” of adjacent base metal (minimum 50% examination coverage) (Primary component) 9. Procedures will be revised to require visual examinations (EVT-1) for 100% of the OD surface of the core barrel lower flange weld and ¾“ adjacent base metal (minimum 50% examination coverage) (Expansion component)	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	10. Procedures will be revised to perform inspections of control rod guide tube (CRGT) thermal sleeves as indicated in MRP 2018-027. MRP 2018-027 refers to the Westinghouse NSAL 18-1 recommendation that, based on operating experience (OE) from international PWR plants related to wear of reactor vessel closure head control rod drive mechanism (CRDM) thermal sleeve flanges resulting in control rod stoppage during plant restart operations, a visual inspection should be performed during the next refueling outage after issuance of the NSAL, and during each subsequent refueling outage, for the tops of the CRGTs to determine whether any thermal sleeves have lowered significantly or are in a failed state. For the Surry plants, the guidance is to look for shiny marks on the top edge of the upper guide tube enclosure. Also, during the next under-head inspection, the guidance is to perform a visual inspection of the bottom of the thermal sleeve guide funnels to look for any shiny surfaces on the bottom surface of the guide funnel that would indicate that the thermal sleeve guide funnels have dropped to a point where they are in contact with the top of the guide tube. A visual inspection of thermal sleeve guide funnel elevations is recommended to identify whether any sleeves are noticeably lower than others (Primary component). 11. Procedures will be revised to require visual examinations (VT-3) for the following: a. Top and bottom edges of baffle plates to identify misalignment (Primary component). b. General condition of the baffle plates to identify warping or void swelling (Primary component). c. Surfaces of the upper internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component). d. Surfaces of the lower internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component). e. Clevis insert bolts and clevis insert dowels (Primary component). 12. Procedures will be revised for contingency tasks to require inspection of the following expansion components if necessitated by relevant indications being found for associated primary components: a. Remaining control rod guide tube lower flange welds not inspected as Primary component (EVT-1) b. Bottom-mounted instrumentation column bodies (100% of BMI column bodies for which difficulty is detected during flux thimble insertion / withdrawal; VT-3) c. Lower support column bodies (25% of column bodies as visible from above the core plate; VT-3) d. Barrel-former bolts (100% of accessible bolts, minimum of 75% of the total population; UT) e. Lower support column bolts (100% of accessible bolts, minimum of 75% of the total population; UT) 13. Procedures will be revised to require that the inspections for the radial support keys and clevis inserts are to include the Stellite wear surfaces (Primary component, MRP 2018-022). 14. Procedures will be revised to require visual inspections (VT-3) of the guide cards in at least 37 of the 48 control rod guide tubes, and will include associated acceptance criteria. Guidance from WCAP-17451-P, "Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections," and MRP 2018-07, "Transmittal of NEI 03-08 Needed Guidance to Address Accelerated Guide Card Wear Operating Experience (OE) Discussed in NSAL-17-1," will be included for the inspection of control rod guide cards.	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	15. Procedures will be revised to require visual examinations (EVT-1), and will include associated acceptance criteria, for 100% of one side of the accessible surfaces of the core barrel lower girth weld and ¾” of adjacent base metal (minimum 50% examination coverage). (Primary component) 16. Procedures will be revised for contingency tasks to inspect the following expansion components if necessitated by relevant indications being found for associated primary components, and will include associated acceptance criteria: a. Core barrel upper, middle, and lower axial welds (100% of weld length – 50% examination coverage; EVT-1) b. Core barrel upper girth weld (100% of weld length – 50% examination coverage; EVT-1) c. Core barrel lower flange weld (100% of weld length – 50% examination coverage; EVT-1) d. Lower support forging (25% of bottom surface; VT-3) e. Upper core plate (25% of accessible surfaces; VT-3) 17. A procedure for visual examinations will be revised to identify the examiner qualifications which are applicable for EVT-1 examinations.	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.
8	*Flow-Accelerated Corrosion* program	The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include a re-evaluation of systems currently excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time to ensure that an adequate basis exists to justify continuing this exclusion.	B2.1.8	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	The *Bolting Integrity* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to provide inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 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 feet to four 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. 2. Procedures will be revised for inspections of pressure-retaining closure bolting in locations that preclude detection of joint leakage, such as in submerged environments or where the piping system contains air for which leakage is difficult to detect. The inspections will be performed to detect loss of material. A requirement will be included to inspect bolt heads when made accessible, and bolt threads if joints are disassembled. At a minimum, in each 10-year interval during the subsequent period of extended operation, inspections shall be completed for a representative sample of at least 20% of the population, up to a maximum of nineteen, for each material/environment combination. 3. A new procedure will be developed to provide guidance for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination is not corrected by repair or replacement, thus requiring that additional inspections be performed. The number of additional inspections will be 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/aging effect combination are required for each inspection that did not meet the acceptance criterion. For a two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same material, environment, and aging effect combination. The additional inspections are to be completed within the same interval (e.g., refueling outage or 10-year inspection interval). If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the Corrective Action Program.	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

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
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. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program. 2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation. 3. The internal lining of 24 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation. 4. Procedures will be revised to remove reference to the carbon steel piping that was replaced and will include the replacement material. 5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement. 6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the Structures Monitoring program (B2.1.34) that are consistent with the requirements of ACI 349.3R. 7. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering. 8. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results. 9. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses. 10. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions. 11. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing “hoop” bands or rust staining from such reinforcing elements. 12. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation.	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	13. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.	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
12	*Closed Treated Water Systems* program	The *Closed Treated Water Systems* program is an existing condition monitoring and mitigation program that will be enhanced as follows: 1. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 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 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 component internal inspections, accessible surfaces will be inspected, subject to a minimum 20% surface area examination coverage. 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. The surface to be examined should be clean and free of corrosion products, slag, dirt, grease, and scale, loose or cracked paint or any foreign material that interferes with examination results. If protective coatings are present, the condition of the coating will be documented. 2. A new procedure will be developed to specify that 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, 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 nineteen components per population at each unit 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. 3. A new procedure will be developed 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. A new procedure will be developed 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 at both Unit 1 and Unit 2. 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. Procedures will be revised to specify visual inspections for the effects of general corrosion, deformation, cracking, and wear on the rails in the rail system. 2. Procedures will be revised to specify visual inspections for general corrosion, deformation, cracking, wear and loose or missing fasteners and other conditions indicative of loss of bolting preload for the new fuel transfer elevator.	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 condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to perform opportunistic visual inspections of internal surfaces of compressed air system components downstream of the dryers to verify the effectiveness of the compressed air system control of moisture (dewpoint) and particulate. Visual inspection results will be compared to previous results to ascertain if adverse long-term trends exist. Deficiencies will be documented in the Corrective Action Program and evaluations performed for test or inspection results that do not satisfy established criteria as defined in the applicable procedures.	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 and performance monitoring program that is credited.	B2.1.15	Ongoing

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. Procedures inspection guidance will be revised to require replacement of any sprinkler that shows any of the following: leakage, corrosion, physical damage, loading, painting unless painted by the sprinkler manufacturer, or incorrect orientation. Sprinklers at the following locations will be added to the test scope: The Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building. 2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner. For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. 3. Procedures will be revised to specify: a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow. b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action. c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination. d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures. 4. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests. 5. Procedures for hydrant flushing will be revised to require fully opening the hydrant and fully flowing the hydrant for no less than one minute and until foreign material has cleared. In addition, procedures will be revised to observe draining of the hydrant barrel and also require the barrel be pumped dry should it not drain within 60 minutes. Hydrants outside the protected area that are within the scope of subsequent license renewal will be added to the flush scope.	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	6. The Fire Water System program will be revised to periodically inspect the insulated exterior surfaces of the fire water tanks on a 10-year frequency during the subsequent period of operation. Insulation is removed to provide a minimum inspection population of 25 one-square foot samples. The samples will be distributed in such a way that inspections occur on the tank dome, near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring. 7. Procedures for mainline strainer flushing will be revised to require flushing until clear water is observed after each operation or flow test. In addition to flushing after operation, the Radwaste Facility mainline strainer will require an inspection every five years for damaged and corroded parts. 8. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. 9. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. 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 visual internal inspections of piping by removing a hydraulically remote sprinkler, 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 visual internal inspections of piping by removing a hydraulically remote nozzle, 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 visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 10. Procedure 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	11. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer ‘1A’ deluge sprinkler piping will be reconfigured to allow drainage. 12. Procedures 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. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe w	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 an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require periodic visual inspections of the refueling water storage tanks (RWSTs) be performed at each outage to confirm that the insulation caulking/sealant at the RWST concrete foundation is intact. The visual inspections of caulking/sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the caulking/sealant will be repaired or replaced and follow-up examination of the tank's surfaces conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWST external insulation is removed and sampled for external surface visual examinations. 2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs and CATs be performed to identify any loss of material or cracking. A minimum of either 25, one square foot sections or 20% of the surface area of insulation will be required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation. 3. Procedures will be revised to require ECST weep holes be inspected for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed. Accessible external metallic tank surfaces visible from inside the ECST piping penetration house will also require inspection once each refueling cycle as an indication of external ECST surface condition. Volumetric examination thickness measurements of the bottom of both ECMTs (100% of the surface exposed to soil) and both emergency condensate storage tanks will be performed and will occur during each 10-year period starting ten years before the subsequent period of extended operation. Results will be forwarded to engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates. 4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of both FWSTs and both RWSTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates. 5. For the carbon steel tanks (FWST, ECST, ECMT), procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, and surface conditions. The revised procedure will require the inspector confirm adequate lighting is available 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 is recommended. For distant surface inspections, viewing aids such as binoculars may be used. For internal inspections, accessible surfaces will be inspected. Cleaning will be performed as necessary to allow for a meaningful examination. If protective coatings are present, the condition of the coating will be noted.	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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
17	*Outdoor and Large Atmospheric Metallic Storage Tanks* program	6. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191. If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected. b. For other sampling based inspections 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 at the other unit. The additional inspections will be completed within the interval (i.e., 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. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.	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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
18	*Fuel Oil Chemistry* program	The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that will be enhanced as follows: 1. Procedures will be revised to include the emergency diesel generator (EDG) fuel oil base tanks within the scope of the *Fuel Oil Chemistry* program. 2. Existing procedures will be revised to include a requirement for quarterly sampling of the EDG auxiliary fuel oil tanks and EDG fuel oil base tanks for particulates and water. 3. Procedures will be revised to require the following fuel oil storage tanks within the scope of subsequent license renewal be drained, cleaned, and the internal surfaces visually inspected for degradation within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation: • Underground fuel oil storage tanks • AAC diesel generator fuel oil tank If degradation is found during the internal visual inspection, bottom thickness measurements will be performed. Visual and volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute. 4. Procedures will be developed to perform periodic bottom thickness measurements of the following tanks within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation: • EDG auxiliary fuel oil tanks • Diesel fire pump fuel oil tank • Emergency service water pump fuel oil tank Volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute. 5. Procedures will be developed to require an engineering evaluation be performed to document, evaluate, and trend visual and volumetric (as applicable) inspection results for the following fuel oil storage tanks: • Underground fuel oil storage tanks • AAC diesel generator fuel oil tank • EDG auxiliary fuel oil tanks • Diesel fire pump fuel oil tank • Emergency service water pump fuel oil 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
18	*Fuel Oil Chemistry* program	The procedures will require unacceptable inspection results, as determined in the engineering evaluation, be documented in the Corrective Action Program. Bottom thickness measurements will be required to be evaluated against the design thickness and corrosion allowance. The frequency between future inspections will not be allowed to be reduced if bottom thickness measurements indicate the corrosion allowance will be exceeded prior to the next scheduled inspection. If a tank does not have a stated corrosion allowance, the tank will be evaluated for acceptability in the engineering evaluation. The engineering evaluation will evaluate the need to reduce the time period between future inspections based on inspection results. 6. Prior to the subsequent period of extended operation, a one-time inspection will be performed on the accessible internal surfaces on one EDG fuel oil base tank at SPS. Inspection will be limited due to the restricted accessibility through the tank sampling port. A visual inspection will be performed using a boroscope or equivalent instrument which will provide an acceptable level of information regarding tank degradation on the accessible internal surfaces. 7. Procedures will be revised to require a biocide be added when biological activity is detected or if there is evidence of tank internal corrosion.	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 will be enhanced as follows: 1. The RV Material Surveillance program for Unit 1 will be amended for Capsule Y to be pulled during the subsequent period of extended operation. Capsule Y will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. 2. The RV Material Surveillance program for Unit 2 will be amended for Capsule T to be pulled during the subsequent period of extended operation. Capsule T will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.	B2.1.19	Program and SLR enhancements will be implemented 6 months prior to the subsequent period of extended operation. This program includes removal and testing of at least one capsule during the subsequent period of extended operation, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
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. The One-Time Inspection program will perform a magnetic particle test inspection of the continuous circumferential transition cone closure weld on each steam generator (minimum 25% examination coverage of each weld) prior to the subsequent period of extended operation. 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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
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 since 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. 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 a new condition monitoring program that augments the existing ASME Code, Section XI requirements and is applicable to ASME Code Class 1 small-bore piping and systems with a NPS diameter less than 4 inches and greater than or equal to 1 inch. This program provides for volumetric examination of a sample of full penetration (butt) welds and partial penetration (socket) welds in Class 1 piping to manage cracking due to stress corrosion cracking or thermal or vibratory fatigue loading. Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. The extent and schedule for volumetric examination is based on plant-specific operating experience and whether actions have been implemented that effectively mitigate the cause(s) of any past cracking. The program provides for a one-time inspection of a sample of the population of welds (butt welds or socket welds) for plants that have not experienced cracking or have experienced cracking but have implemented corrective actions, such as a design change, to effectively mitigate the cause(s) of the cracking. The program provides for periodic inspection of a sample of the population of welds (butt welds or socket welds) that have experienced cracking and have not implemented corrective actions to effectively mitigate the cause(s) of the cracking. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.22	Program will be implemented and inspections are completed within 6 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
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. The Engineering walkdown procedure will be revised to include an item in the walkdown checklist to inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture. 2. The Engineering walkdown procedure will be revised to add the following requirements: a. Metallic Components • No surface imperfections, loss of wall thickness, flaking, or oxide coated surfaces • No blistering of protective coating • No evidence of leakage (for detection of cracks) on the surfaces of stainless steel and aluminum components • No accumulation of debris on air-side heat exchanger surfaces b. Elastomers and Flexible Polymers • No exposure of reinforcing fibers, mesh or underlying metal (for elastomers or flexible polymers with internal reinforcement) • No blistering, loss of thickness, dimensional change, or scuffing • No hardening of elastomeric elements as evidenced by a loss of suppleness during tactile inspection c. Insulation Metallic Jacketing • Inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture. d. HVAC Closure Bolting • Check that a sample of closure bolting that is in reach is not loose 3. The Engineering walkdown procedure 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, the enhancement will also specify that such surfaces will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. 4. The Engineering walkdown procedure will be revised to provide non-ASME Code inspection guidance related to lighting, distance and offset for walkdown 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. 5. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. A minimum of 25 inspections for cracking will be performed from each of the stainless steel and aluminum component populations assigned to the program every ten years. For insulated components exposed to condensation, a minimum of 25 one foot axial length sections and components for each material and environment combination will be inspected for loss of material and cracking after the insulation is removed. 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.	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	6. The Engineering walkdown procedure will be revised to specify that visual inspection of elastomers and flexible polymers will be supplemented by tactile inspection to detect hardening. Visual inspections will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 7. A new procedure will be developed to evaluate and project the rate of any 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. 8. A new procedure will be developed 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. 9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections to detect cracking in aluminum and stainless steel 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 at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., 10-year inspection interval) in which the original inspection was conducted.	B2.1.23	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
24	*Flux Thimble Tube Inspection* program	The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that will be enhanced as follows: 1. An inspection procedure will be developed specifically for flux thimble tube eddy-current inspections, rather than continuing to use a generic procedure for tubing inspection. The procedure will include the acceptance criterion, with the basis, for loss of material for the inner flux thimble tube, and identify remediating actions to be implemented if the acceptance criterion is exceeded.	B2.1.24	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	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. Procedures will be revised to require inspection of metallic components for flaking or oxide-coated surfaces. 2. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following: a. Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., “ballooning” and “necking”) b. Loss of wall thickness c. Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers 3. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 4. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 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 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 procedure will require the condition of the coating to be documented. 5. A new procedure will be developed to specify that 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 nineteen components per population at each unit 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. 6. A new procedure will be developed to evaluate and project the rate of any 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.	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	7. A new procedure will be developed 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. 8. A new procedure will be developed to specify that 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 at both Unit 1 and Unit 2. 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.	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. Procedures will be revised to incorporate existing guidelines for lube oil and electro-hydraulic control fluids into sampling procedures. 2. Procedures will be revised to include a statement that phase-separated water in any amount is not acceptable.	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
27	*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. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings. 2. Procedures will be revised to include visual inspection requirements and acceptance criteria for: a. Absence of cracking in fiberglass reinforced plastic components and evaluation of blisters, gouges, or wear b. Minor cracking and loss of material in concrete or cementitious material provided there is no evidence of leakage exposed or rust staining from rebar or reinforcing "hoop" bands 3. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. Alternatives will be demonstrated to be effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured. When using the electrical resistance corrosion rate probes: a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data	B2.1.27	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
28	*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 an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require additional inspections of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection frequencies will be modified, as necessary, to ensure consistency with NUREG-2191: • Circulating water system waterbox air separating tanks • Condensate polishing outlet piping • Vacuum priming tanks • Vacuum priming seal water separator tanks • Auxiliary steam drain receiver tank • Water treatment piping • Flash evaporator demineralizer isolation valve • Pressurizer relief tanks 2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage. 3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program. 4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. 5. Procedures will be revised to require cementitious coatings/linings inspectors to have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience. 6. Procedures will be revised to require a pre-inspection review of the previous “two” condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities. 7. Procedures will be revised to require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material. 8. Procedures will be revised to permit the “removal” of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation.	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
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	9. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if: a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal b. The potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered) adhesion testing (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area c. An evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component and d. Follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced. 10. Procedures will be revised to require additional inspections if one of the license renewal inspections does not meet acceptance criteria due to current or projected degradation.	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	*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. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” EPRI TR-104213, “Bolted Joint Maintenance & Application Guide,” and the additional recommendations of NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants.” 2. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” will be used. 3. Procedures will be revised to specify surface examination and acceptance criteria, in addition to visual examination, to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis. 4. Procedures will be revised to specify a one-time volumetric examination of metal liner surfaces that are inaccessible from one side if triggered by plant-specific operating experience. Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side.	B2.1.29	Program and SLR 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 IWL* program	The *ASME Section XI, Subsection IWL* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to specify that inspection results be compared to previous results to identify changes from prior inspections, and that quantitative measurements are recorded and trended for applicable parameters monitored or inspected. 2. Procedures will be revised to specify that inspection results be compared to previous results to determine if degradation is passive for application of second-tier acceptance criteria as specified in ACI 349.3R-02, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."	B2.1.30	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
31	*ASME Section XI, Subsection IWF* program	The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be enhanced to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 2. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants will be in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339. 3. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication, “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” will be used. 4. Procedures will be revised to specify that for NSSS component supports, Class 1 high strength bolting greater than one inch nominal diameter, including ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), will be monitored for SCC. 5. Procedures 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. 6. Procedures will be revised to specify that, for NSSS component supports, high-strength bolting greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts.	B2.1.31	Program will be implemented and a one-time inspection of an additional 5% of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports is conducted within 5 years prior to the subsequent period of extended operation, and are to be completed prior to the subsequent period of extended operation, are 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.
32	*10 CFR 50, Appendix J* program	The *10 CFR 50, Appendix J* program is an existing performance monitoring program that is credited.	B2.1.32	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
33	*Masonry Walls* program	The *Masonry Walls* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to clarify qualifications for personnel performing inspections of masonry walls and concrete to be consistent with ACI 349.3R-02. 2. Procedures will be revised to explicitly address the trending of inspection results and projection to the next inspection interval. The procedure will be revised to include acceptance criteria for masonry wall inspections that will be used to ensure observed aging effects (cracking, loss of material, or gaps between the structural steel supports and masonry walls) do not invalidate the evaluation basis of the wall or impact its intended function.	B2.1.33	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
34	*Structures Monitoring* program	The *Structures Monitoring* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. 2. Procedures will be revised to 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used. 3. Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002. 4. Procedures will be revised to inspect wooden power poles on a 10-year frequency.	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
35	*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. Procedures will be revised to provide guidance for specification of bolting material, lubricants and sealants, and installation torque or tension to prevent degradation and assure structural bolting integrity. 2. Procedures will be revised to specify the preventive actions for storage discussed in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts” for ASTM A325, ASTM F1852, ASTM F2280, and/or ASTM A490 structural bolts. 3. Procedures will be revised for concrete inspection to require at least five years of experience (or ACI inspector certification) to be consistent with ACI 349.3R-2002.	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	*Protective Coating Monitoring and Maintenance* program	The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require that a pre-inspection review of the previous “two” condition assessment reports be performed prior to each refueling outage.	B2.1.36	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
37	*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. A new procedure will be developed that will include guidance for the identification of adverse localized environments of temperature, moisture, radiation, contamination, and oxygen. 2. A new procedure will be developed that includes 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. 3. A new procedure will be developed that includes an inspection frequency of at least once every ten years. 4. A new procedure will be developed that includes the addition of jacket surface and connection covering material anomalies including embrittlement, melting, swelling, and surface contamination. 5. A new procedure will be developed that includes the performance of a review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation. 6. A new procedure will be developed that describes acceptance criteria for both tests and visual inspections of the electrical cable and connection insulation material. 7. A new procedure will be developed that includes 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).	B2.1.37	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 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 will be enhanced as follows: 1. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment to evaluate reduced electrical insulation resistance by measuring cable resistance and capacitance. 2. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes recommendations for types of electrical insulation tests including insulation resistance tests, time domain reflectometry tests, or other tests judged to be effective in determining cable system insulation physical, mechanical, and chemical properties. 3. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes a test frequency of at least once every ten years with the first test completed prior to the subsequent period of extended operation. 4. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes acceptance criteria for the recommended test methods. 5. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment. The new procedure will include corrective actions and a requirement for an engineering evaluation to be performed when acceptance criteria are not met. The engineering evaluation will include a determination of whether the test frequency needs to be increased.	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
39	*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. Procedures will be revised to require inspection of in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. 2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly. 3. A procedure will be created for testing medium-voltage cable that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation. 4. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection. 5. A new recurring event and maintenance schedule will be created for testing the "A" RSST cables at least once every six years. 6. A new recurring event and maintenance schedule will be created for testing the "B" RSST cables at least once every six years. 7. A new recurring event and maintenance schedule will be created for testing the "C" RSST cables at least once every six years. 8. A new procedure will be created for testing medium-voltage cable that includes a requirement that the specific type of test performed will be a proven test, utilizing one or more tests 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, for detecting deterioration of the insulation system due to submergence (e.g., selected test is applicable to the specific cable construction: shielded and non-shielded, and the insulation material under test). 9. A new procedure will be created for testing medium-voltage cable that includes a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation. 10. A new procedure will be created for testing medium-voltage cable that includes acceptance criteria for tests and inspections.	B2.1.39	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
40	*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 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), instrument and control cables, exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.40	Program will be implemented 6 months prior to the subsequent period of extended operation.
41	*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), exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.41	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
42	*Metal-Enclosed Bus* program	The *Metal-Enclosed Bus* program is an existing condition monitoring program that will be enhanced as follows: 1. Inspection procedures similar in scope and content to the procedures used to inspect other metal enclosed bus within scope of subsequent license renewal will be developed for the in-scope metal enclosed bus (MEB) associated with the 1A2 480V bus. 2. For inaccessible MEB internal or external segments, procedures will be revised to require initiation of a condition report that will result in an engineering evaluation of the inaccessible MEB segments that, together with the accessible MEB inspection and test program, will continue to maintain the MEB consistent with the current licensing basis during the subsequent period of extended operation. 3. Procedures will be revised to require inspection of accessible internal portions (bus enclosure assemblies) of MEBs for cracks, corrosion, and foreign debris. Accessible bus electrical insulation material will be inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, discoloration, or swelling, indicating overheating or aging degradation. Accessible internal bus insulating supports will be inspected for structural integrity and signs of cracks. Accessible gaskets, boots, and sealants will be inspected for elastomer degradation including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength that could permit water or foreign debris to enter the bus. 4. Procedure revisions will include a requirement for a sample of accessible bolted connections not covered with heat shrink tape or boots to be inspected for loose or corroded bolted connections and damaged hardware including cracked or split washers. 5. Inspection procedures will be revised to add a note stating that 20% of the accessible bolted connection population, with a maximum of 25, is a representative sample. 6. A new recurring event and maintenance schedule will be created to inspect MEB associated with the 0-AAC-SW-0L bus on a maximum ten-year frequency. The first occurrence will be scheduled prior to the subsequent period of operation. 7. A new recurring event and maintenance schedule will be created to inspect MEB associated with the 1-EP-LCC-1A2 bus on a maximum ten-year frequency. The first occurrence will be scheduled prior to the subsequent period of operation. 8. Procedures will be revised to trend bus connection resistance values to provide information on the rate of connection degradation. 9. Accessible electrical insulation materials will be verified free from regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, and swelling. Accessible MEB internal surfaces will be verified to show no indications of corrosion, cracks, and foreign debris. Accessible elastomers (e.g., gaskets, boots, and sealants) will be verified to show no indications of surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength. 10. Procedures will be revised to specify that when any acceptance criterion is not met, the unacceptable results are entered into the Corrective Action Program	B2.1.42	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
43	*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 electrical connections tested prior to the subsequent period of extended operation. 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.	B2.1.43	Program will be implemented 6 months prior to the subsequent period of extended operation.
44	*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.	B2.1.44	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
45	*Fatigue Monitoring* program	The *Fatigue Monitoring* program is an existing preventive program that will be enhanced as follows: 1. The program cycle counting procedures will be revised to add the "Normal Charging and Letdown Shutdown and Return to Service" transient cycle associated with the ASME Code, Section XI, Appendix L analysis. 2. Procedures will be revised to require monitoring and tracking of transient cycles associated with the ASME Code, Section XI, Appendix L analysis be performed between the inspections for each ASME Code, Section XI, Appendix L location. Consistent with existing program cycle counting, a surveillance limit will be established to initiate corrective action prior to exceeding transient cycle assumptions in the ASME Code, Section XI, Appendix L analysis. 3. Procedures will be revised to expand existing corrective action guidance associated with exceeding a cycle counting surveillance limit to recommend consideration of component repair, component replacement, performance of a more rigorous analysis, performance of an ASME Code, Section XI, Appendix L flaw tolerance analysis, or scope expansion to consider other locations with the highest expected U_{en} values.	B3.1	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
46	*Neutron Fluence Monitoring* program	The *Neutron Fluence Monitoring* program is an existing condition monitoring program that is credited.	B3.2	Ongoing
47	*Environmental Qualification of Electric Equipment* program	The *Environmental Qualification of Electric Equipment* program is an existing program that will be enhanced as follows: 1. Existing procedures will be enhanced to include a requirement for plants that are entering or have entered their subsequent period of extended operation to perform a walkdown once prior to the subsequent period of extended operation and every ten years thereafter. Accessible electrical EQ equipment will be visually inspected and the EQ environment evaluated to identify in-scope electrical equipment subjected to an adverse localized environment (ALE). If an ALE is found, evaluation of the impact of the ALE on EQ electrical equipment, including qualified life, will be performed. 2. Existing procedures will be enhanced to evaluate and take appropriate corrective actions, which may include changes to qualified life, when an unexpected adverse localized environment or condition is identified during operational or maintenance activities that affect the qualification of electrical equipment.	B3.3	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Intentionally Blank

Surry Power Station

Units 1 and 2

Application for Subsequent License Renewal

Appendix B
Aging Management Programs

Intentionally Blank

List of Tables

List of Figures

NONE

Intentionally Blank

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.
- Condition 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 Surry Power Station (SPS) Subsequent License Renewal Application (SLRA).

Existing initial license renewal aging management 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 Energy 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 SPS 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 non safety-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 creation 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 Dominion 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. Plant 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 non safety-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 SPS organizational structure, responsibilities, authorities, and personnel qualification requirements is provided in the Updated Final Safety Analysis Report (UFSAR) and in the Dominion Energy QA Program. The organizational structure, responsibilities, authorities, and personnel qualification requirements conform to 10 CFR 50, Appendix B. The Dominion Energy 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 Dominion 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 non safety-related structures, systems, and components (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 Dominion OE Program interfaces with, and relies on, active participation in the INPO OE program, as endorsed by the NRC.

OE is used to enhance plant programs, prevent repeat events, and prevent events that are similar to those that have occurred at other plants. Personnel 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 the INPO Consolidated Event System (ICES), consistent with the guidance in NEI 14-13, “Use of Industry Operating Experience for Age-Related Degradation and Aging Management Programs.” In addition, as further discussed below, 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.” 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.

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.

License Renewal Aging Management Program Effectiveness and Oversight

Consistent with the guidance in Section 6 of Appendix B of NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR 54 for Subsequent License Renewal,” effectiveness reviews of initial license renewal aging management programs/activities were performed, and are presented within the SLRA Appendix B AMP sub-sections that are most related to those initial license renewal aging management activities (AMAs). For example, there were several initial license renewal AMAs related to water chemistry control. An assessment of the effectiveness of the water chemistry control AMAs (UFSAR Section 18.2.4 and Section 18.2.5) is presented within SLRA Section B2.1.2, which describes the subsequent license renewal *Water Chemistry* aging management program. Surry Power Station is actively managing its current AMAs during the current period of extended operation but seeks to confirm the effective implementation of its AMAs and to identify areas for further improvements that will heighten the effectiveness of aging management both now and during the subsequent period of extended operation.

The following initial license renewal activities effectiveness reviews were performed consistent with NEI 14-12, Revision 0, “Aging Management Program Effectiveness,” to identify gaps related to the effectiveness of the initial license renewal AMAs. In addition, the following oversight activities have identified gaps and associated corrective actions that have been implemented to improve the effectiveness of initial license renewal AMAs.

1. December 2015: An effectiveness review of 15 initial license renewal aging management activities was performed. The AMAs selected for review were evaluated against the performance criteria detailed in NEI 14-12 for the following elements:

    - Detection of Aging Effects – Detection should occur with sufficient time to implement preventive actions before loss of structure or component-intended function.
    - Corrective Actions – Actions, including cause evaluation and prevention of recurrence, should be timely.
    - Operating Experience – Industry operating experience and plant operating history, including corrective actions, are used to inform the AMAs.

    The effectiveness review identified certain gaps associated with the following initial license renewal AMAs: Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16), Load Handling Cranes and Devices Activity (UFSAR Section 18.2.10), Fire Protection Program (UFSAR Section 18.2.7), General Condition Monitoring Activity (UFSAR Section 18.2.9), Work Control Process Activity (UFSAR Section 18.2.19), and Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4). The gaps and corrective actions are discussed in the operating experience summary of the applicable Appendix B AMPs (B2.1.8, B2.1.13, B2.1.16, B2.1.23, B2.1.25, B2.1.37, and B2.1.39 respectively).

2. December 2016: As part of oversight review activities, initial license renewal administrative controls were evaluated to confirm changes to credited initial license renewal AMAs were reviewed and updated, as necessary, to ensure consistency with the licensing basis. Specific actions completed and documented during the evaluation included confirmation that:

   - Procedures credited for license renewal were identified;
   - Procedures were consistent with the licensing basis and bases documents;
   - Procedures contained a reference to conduct an aging management review prior to revising; and
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document.

   Procedure changes required as a result of this evaluation were documented in the Corrective Action Program and were completed as necessary to eliminate the identified gaps.

3. November 2017: As part of oversight review activities, AMA owners confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management program commitments required in UFSAR Chapter 18. Of the initial license renewal programs, 20 AMAs were evaluated as acceptable with no further corrective actions. Gaps were identified with the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6), Fire Protection Program (UFSAR Section 18.2.7), Load Handling Cranes and Devices Activity (UFSAR Section 18.2.10), and Service Water System Inspections Activity (UFSAR Section 18.2.17) programs. The gaps were documented in the Corrective Action Program, and corrective actions implemented. The gaps and corrective actions are discussed in the operating experience summary of the applicable Appendix B AMPs (B2.1.34, B2.1.16, B2.1.13, and B2.1.11 respectively).

4. January 2018: Additional effectiveness reviews of initial license renewal AMAs were conducted. The SPS program owners evaluated the AMAs against seven performance criteria from NEI 14-12 that were adapted for the effectiveness reviews and summarized as follows:

   - Implementing procedures contain acceptance criteria for each parameter monitored or inspected.
   - Acceptance criteria anticipate rates of change and margin to loss of function.
   - Inspections and examinations are conducted at appropriate intervals.
   - Operating experience is considered in evaluating the appropriateness of technique and frequency and adoption of new techniques as they become available.
   - Industry operating experience and plant operating experience, including corrective actions, are used to inform AMAs.
   - There are no significant findings from the NRC, industry peers, or from internal sources against the program.
   - Implementing procedures are consistent with license renewal commitments.

   No gaps were identified with twenty-three of the twenty-four initial license renewal aging management activities. Gaps were identified with the Work Control Process Activity (UFSAR Section 18.2.19). The gaps were documented in the Corrective Action Program, and corrective actions initiated. The effectiveness reviews are presented in the operating experience summary of the applicable Appendix B AMPs.

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 SPS Program

NUREG-2191 Number	NUREG-2191 Program	Surry 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

Table B1-1
Correlation: NUREG-2191 Program with SPS Program

NUREG-2191 Number	NUREG-2191 Program	Surry Power Station Program	Appendix B Reference
XI.M18	Bolting Integrity	Bolting Integrity	B2.1.9
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 SPS 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

Table B1-1
Correlation: NUREG-2191 Program with SPS Program

NUREG-2191 Number	NUREG-2191 Program	Surry Power Station Program	Appendix B Reference
XI.M37	Flux Thimble Tube Inspection	Flux Thimble Tube Inspection	B2.1.24
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	Not Applicable. SPS spent fuel storage racks do not include any neutron absorbing materials	N/A
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks	B2.1.27
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	B2.1.28
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE	B2.1.29
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL	B2.1.30
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF	B2.1.31
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J	B2.1.32
XI.S5	Masonry Walls	Masonry Walls	B2.1.33
XI.S6	Structures Monitoring	Structures Monitoring	B2.1.34
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants	B2.1.35
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance	B2.1.36

Table B1-1
Correlation: NUREG-2191 Program with SPS Program

NUREG-2191 Number	NUREG-2191 Program	Surry Power Station Program	Appendix B Reference
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	B2.1.37
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	B2.1.38
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	B2.1.39
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	B2.1.40
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	B2.1.41
XI.E4	Metal-Enclosed Bus	Metal-Enclosed Bus	B2.1.42
XI.E5	Fuse Holders	Not applicable. SPS has no stand alone fuse holders with the scope of SLR.	N/A
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	B2.1.43
XI.E7	High-Voltage Insulators	High-Voltage Insulators	B2.1.44
X.M1	Fatigue Monitoring	Fatigue Monitoring	B3.1

Table B1-1
Correlation: NUREG-2191 Program with SPS Program

NUREG-2191 Number	NUREG-2191 Program	Surry Power Station Program	Appendix B Reference
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	Not applicable. SPS containments do not have post tensioned tendon groups.	N/A

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.

- Fatigue Monitoring (Section B3.1)
- Neutron Fluence Monitoring (Section B3.2)
- Environmental Qualification of Electric Equipment (Section B3.3)

Intentionally Blank

B2 AGING MANAGEMENT PROGRAMS

Table B2-1 lists the aging management programs described in this appendix and identifies the programs consistency with NUREG-2191. 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
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	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		X
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	X	
Bolting Integrity	B2.1.9	Existing	X	
Steam Generators	B2.1.10	Existing		
Open-Cycle Cooling Water System	B2.1.11	Existing	X	X
Closed Treated Water Systems	B2.1.12	Existing	X	X

Table B2-1
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	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		
Fire Water System	B2.1.16	Existing	X	X
Outdoor and Large Atmospheric Metallic Storage Tanks	B2.1.17	Existing	X	X
Fuel Oil Chemistry	B2.1.18	Existing	X	X
Reactor Vessel Material Surveillance	B2.1.19	Existing	X	
One-Time Inspection	B2.1.20	New		
Selective Leaching	B2.1.21	New		
ASME Code Class 1 Small-Bore Piping	B2.1.22	New		X
External Surfaces Monitoring of Mechanical Components	B2.1.23	Existing	X	
Flux Thimble Tube Inspection	B2.1.24	Existing	X	
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B2.1.25	Existing	X	
Lubricating Oil Analysis	B2.1.26	Existing	X	
Buried and Underground Piping and Tanks	B2.1.27	Existing	X	
Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B2.1.28	Existing	X	X
ASME Section XI, Subsection IWE	B2.1.29	Existing	X	

Table B2-1
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
ASME Section XI, Subsection IWL	B2.1.30	Existing	X	
ASME Section XI, Subsection IWF	B2.1.31	Existing	X	
10 CFR Part 50, Appendix J	B2.1.32	Existing		
Masonry Walls	B2.1.33	Existing	X	
Structures Monitoring	B2.1.34	Existing	X	
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B2.1.35	Existing	X	
Protective Coating Monitoring and Maintenance	B2.1.36	Existing	X	
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.37	Existing	X	
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	B2.1.38	Existing	X	
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.39	Existing	X	
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.40	New		

Table B2-1
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.41	New		
Metal-Enclosed Bus	B2.1.42	Existing	X	X
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.43	New		
High-Voltage Insulators	B2.1.44	New		X
Fatigue Monitoring	B3.1	Existing	X	
Neutron Fluence Monitoring	B3.2	Existing		
Environmental Qualification of Electric Equipment	B3.3	Existing	X	

B2.1 AGING MANAGEMENT PROGRAM DETAILS

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, loss of fracture toughness, and loss of material. The program consists of periodic volumetric, surface, and/or visual examination and leakage tests of ASME 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* aging management program implements the required component examination schedule in accordance with ASME Code, Section XI, Subsection 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 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 IWA-4000.

Additional examinations not required by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program, but using ASME Code, Section XI inspection techniques and acceptance criteria are performed in accordance with the Augmented Inspection program.

For the current fifth 10-year inspection interval, the ISI program applies the requirements of ASME Code, Section XI, 2004 Edition (no addenda). As required by 10 CFR 50.55a(g)(4)(ii), the ISI program is updated during each successive 120 month inspection interval to comply with the requirements of the edition of the Code that is applicable twelve months before the start of the inspection interval. The ASME Code, Section XI edition used will be 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.

A Risk-Informed Inservice Inspection (RI-ISI) program has been implemented using ASME Code, Section XI, Code Case N-716-1, “Alternative Classification and Examination Requirements Section XI, Division 1." This methodology includes Class 1 piping welds and Class 2 components (excluding attachment welds and supports).

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 subsequent license renewal aging management programs that include augmented requirements:

- *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 (B2.1.31)

The augmented examinations that are listed in the ISI Schedule include the following components:

- Sensitized stainless steel [Class 1, Class 2, and containment spray and recirculation spray]
- High energy lines outside of Containment [main steam and feedwater lines]
- Component supports [the first seismic restraint beyond the defined ASME functional isolation boundary]
- Steam generator feedwater nozzles [feedwater piping welds from the steam generators to the first elbow. Initial inspections are planned for refueling outage 30 (2020 for Unit 1, 2021 for Unit 2)]
- Pressurizer instrument connections
- Pressurizer surge line
- MRP-146 thermal stratification inspections

Inspections for three other aspects of the Augmented Inspection program are included in non-ISI programs. Inspections of Reactor Vessel Incore Detector Thimble Tubes are described in the *Flux Thimble Tube Inspection* program (B2.1.24). Inspections of the Reactor Vessel Head are described in the *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). Inspections of the PWR vessel internals are described in the *PWR Vessel Internals* program (B2.1.7).

NUREG-2191 Consistency

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing program and is 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(s) will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedures will be revised to require inspections be performed for welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix L for the following auxiliary lines:
    - Safety injection
    - Residual heat removal
    - Spray
    - Charging
    - Accumulator
    - Surge

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2005, during the Spring refueling outage, an embedded circumferential indication was detected in a Unit 2 reactor vessel inlet nozzle-to-shell weld region. The indication is classified as an embedded flaw since it meets the ASME Code, Section XI, IWA-3300 guidelines. The embedded indication is located near the outside surface and can be detected from outside the reactor vessel shell and the inlet nozzle bore region. The dimensions of the embedded flaw detected exceeded the allowable flaw size given in ASME Code, Section XI, Table IWB-3512.

A flaw evaluation was performed to demonstrate, using the ASME Code, Section XI, IWB-3600 flaw evaluation guidelines, that the detected embedded flaw is acceptable for continuing plant operation without repair.

2. In November 2009, dye penetrant testing (PT) during ASME Code, Section XI ISI on a Unit 2 four inch pressurizer spray line found two rejectable indications. Those indications were mechanically removed and the remaining wall thickness was confirmed to be acceptable by ultrasonic testing (UT). Scope expansion involved PT and UT of six additional locations. The results were acceptable.

3. In November 2010, a PT examination performed on a weld for a Unit 1 two inch safety injection system pipe found three linear indications on a weld, during the ASME Code, Section XI planned scope of the refueling outage. Controlled grinding did not remove the indications, so a repair/replacement program was created to replace the associated pipe. A scope expansion required examination of four additional welds. The four additional welds were inspected and found to be acceptable.

4. In October 2013, during a PT examination, four rounded indications were identified on a Unit 1 pressurizer spray line. Two indications, when combined together following ASME Code, Section XI rules for proximity, became a rejectable indication. The rejectable indication was on the base metal rather than on a weld. The indication was characterized as fabrication-related, possibly from an arc strike. A work order was completed to remove the surface indication. Subsequent PT results at the excavated location were acceptable.

5. In December 2015, an effectiveness review of the In-service Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the In-service Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11), ISI Program – Reactor Vessel Activity (UFSAR Section 18.2.13), and Augmented Inspection Activities (UFSAR Section 18.2.1) AMAs owners confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activities commitments. No gaps were identified by the review.

8. In January 2018, a fleet self assessment was completed for the Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11). Adherence with INPO guidance for the activity was confirmed. One procedure change was recommended to provide increased consistency among the Dominion Energy sites for the Owner's Activity Reports (OAR-1) when describing "items with flaw or relevant conditions that require evaluation for continued service". The self assessment included an objective to evaluate the sharing of operating experience (OE). No concerns were identified for this topic. OE is discussed during the monthly fleet phone calls for the ISI program. Significant OE is listed in the program health report, and is incorporated into the ISI program, as necessary.

9. In January 2018, an aging management program effectiveness review was performed of the In-service Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11). Information from the summary of that effectiveness review is provided below:

   The ISI Program - Components and Component Support Inspections Activity is meeting or exceeding the requirements consistent with the selected elements of NEI 14-12, "Aging Management Program Effectiveness." Key activities of the AMA that were reviewed include the performance of (non-destructive examinations) NDE to meet the requirements of ASME Code, Section XI and AMA document updates. An ASME Section XI Program is required by law through the Code of Federal Regulations. A10-year period (July 2006 to June 2016) of condition reports and engineering evaluations has been reviewed to identify programmatic issues.

   ISI examinations are scheduled appropriately in the Unit 1 ISI Schedule (Unit 1, Inservice Inspection Schedule, Fifth Inspection Interval, December 13, 2013 to October 14, 2023) and the Unit 2 ISI Schedule (Unit 2, Inservice Inspection Schedule, Fifth Inspection Interval, May 10, 2014 to May 9, 2024) to meet the requirements of ASME Code, Section XI and the Code of Federal Regulations. The Period 1 Fifth Interval ISI examinations have been completed to meet the ASME Section XI Code requirements. The ISI plan and the ISI schedule are updated periodically to implement new code cases of benefit and new rules and regulations, as required. There have been no new issues revealing service induced degradation to date in the fifth Interval.

NRC approved Code Cases and Relief Requests can alter the ISI program in regards to examination technique and frequency. One example of an NRC approved Code Case that has been implemented for the Fifth Interval with significant savings in dose and time expended on required examinations is Code Case N-716-1, “Alternative Classification and Examination Requirements Section XI, Division 1." This Code Case allows selection of examination components most important to safety in regards to Core Damage Frequency and Large Early Release Frequency while eliminating examinations on less safety significant components. This Code Case is approved for use in Regulatory Guide 1.147 “Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1,” Revision 17.

10. In January 2018, an aging management program effectiveness review was performed for the ISI Program – Reactor Vessel Activity (UFSAR Section 18.2.13). Information from that effectiveness review is provided below:

    The Inservice Inspection Program for the Reactor Vessels Activity (ISI-RPV) is meeting or exceeding the requirements consistent with the selected elements of NEI 14-12, “Aging Management Program Effectiveness”. Key activities of the AMA that were reviewed include the performance of NDE (non-destructive examinations) to meet the requirements of ASME Section XI and AMA document updates. An ASME Section XI Program is required by law through the Code of Federal Regulations. A ten-year period (July 2006-June 2016) of Condition Reports (CRs) and Engineering Evaluations has been reviewed to identify programmatic issues.

    ISI examinations for Unit 1 and Unit 2 reactor pressure vessels are scheduled appropriately in the Unit 1 Schedule (Surry Power Station Unit 1, Inservice Inspection Schedule, Fifth Inspection Interval, December 13, 2013 – October 14, 2023) and the Unit 2 ISI Schedule (Surry Power Station Unit 2, Inservice Inspection Schedule, Fifth Inspection Interval, May 10, 2014 – May 9, 2024) to meet the requirements of ASME Section XI and the Code of Federal Regulations. All Period 1 Fifth Interval ISI examinations have been completed to meet the ASME Section XI Code requirements for the reactor vessels. The ISI Plan and Schedule are updated periodically to implement new code cases of benefit and new rules and regulations as required. There have been no new issues revealing service induced degradation for the reactor vessels to date in the 5th Interval.

    NRC approved Code Cases and relief requests can alter the ISI program in regards to examination technique and frequency. Two examples of changes to the ISI Program due to NRC mandated Code Cases N-722-1 “Additional Examinations for PWR Pressure Retaining Welds in Class 1 Components Fabricated With Alloy 600/82/182 Materials” and Code Case N-729-4 “Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzles Having Pressure-Retaining Partial-Penetration Welds” have been implemented. Code Case N-722-1 requires visual examination (a VE examination for boric acid) of the RPV bottom mounted instrumentation penetrations every other refueling outage. Code Case N-729-4 requires a bare metal (insulation removed) visual examination basically every third refueling outage and full NDE (volumetric and/or surface examination) every interval.

11. In January 2018, an aging management program effectiveness review was performed for the Augmented Inspection Activities (UFSAR Section 18.2.1). Information from that effectiveness review is provided below:

    The Augmented Inspection Activities is meeting or exceeding the requirements consistent with the selected elements of NEI 14-12, "Aging Management Program Effectiveness". Key activities of the AMA that were reviewed include the performance of NDE (non-destructive examinations) to meet the committed Augmented Inspection requirements and AMA document updates. A ten-year period (July 2006-June 2016) of Condition Reports (CRs) and Engineering Evaluations has been reviewed to identify programmatic issues.

    Augmented examinations are scheduled appropriately in the Unit 1 Schedule (Surry Power Station Unit 1, Inservice Inspection Schedule, Fifth Inspection Interval, December 13, 2013 – October 14, 2023) and the Unit 2 ISI Schedule (Surry Power Station Unit 2, Inservice Inspection Schedule, Fifth Inspection Interval, May 10, 2014 – May 9, 2024). The Period 1 Fifth Interval examinations have been completed to meet the Augmented requirements. The governing procedure for the Augmented Inspection Activities is updated when affected by Industry directives. Due to corrective actions, the Augmented Inspection Activities AMA was updated to reflect a "visual" examination requirement, not a certified "VT-2", when performing the High Energy Line Walkdown outside of Containment. A "visual" examination was required in the original Technical Specifications.

    Industry operating experience and Industry Working Group recommendations such as letters from the MRP (EPRI Materials Reliability Program) can alter the Augmented Inspection Activities in regards to examination technique and frequency. Two examples are the programs for MRP-227-A, "Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines," and MRP-146, "MRP 146 Thermal Stratification Inspections". The Augmented Inspection Activities AMA provides direction in accordance with the most recent guidance.

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, loss of fracture toughness and loss of material for the ASME 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 manage aging 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, 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.

B2.1.2 Water Chemistry

Program Description

The *Water Chemistry* program is an existing preventive program that manages loss of material, cracking, 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 (PWR) 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, "Pressurized Water Reactor Primary Water Chemistry Guidelines," Revision 7. The Secondary Water Chemistry program is consistent with EPRI Report 3002010645, "Pressurized Water Reactor Secondary Water Chemistry Guidelines," Revision 8.

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 the EPRI Report 3002000505 and includes specific limits for pH, lithium, fluorides, chlorides, sulfates, dissolved oxygen, and other parameters. Zinc injection is used to mitigate stress corrosion cracking (SCC) in the primary systems. Control of reactor coolant and related interfacing system contaminants is maintained by using 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 condensate demineralizers combined with steam generator blowdown. Chemical addition of approved amines (ethanolamine-ETA), is utilized for pH control. Hydrazine is 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 will provide 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.

NUREG-2191 Consistency

The *Water Chemistry* program is an existing program that is consistent, with exception, to NUREG-2191, Section XI.M2, Water Chemistry.

Exception Summary

The following program element(s) are affected:

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. NUREG-2191 indicates that the water chemistry program for pressurized water reactors (PWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines contained in EPRI 3002000505, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” Revision 7 and EPRI 1016555, “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” Revision 7.

   An exception is being taken to use Revision 8 of the “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” which is EPRI Report 3002010645.

<u>Justification for Exception</u>

EPRI Report 3002010645 makes several changes to the tables of control and diagnostic parameters. The changes were based on operating experience and available data on secondary water chemistry and secondary cycle corrosion and provided either clarifications, specificity, or conservatism to the Secondary Water Chemistry Guidelines. Changes are summarized below with justifications for the exception.

<u>Table 5-1 – Wet Layup Steam Generator Sampling</u>

Revision 7 allows a pH control limit of greater than or equal to 9.5 (normally 9.8) if hydrazine concentration is maintained greater than 75 ppm. Revision 8 allows linear interpolation between 9.5 and 9.8 using the concentration of hydrazine in the steam generators to determine the pH control limit. This change provides greater specificity to the pH control limit when hydrazine is maintained within the range of 25 to 75 ppm.

Table 5-3 – Heatup/Hot Shutdown and Startup Feedwater Sampling

Total iron and copper sampling was added in Revision 8 as a diagnostic parameter. The sampling frequency is continuous using integrated sampling. This revision adds conservatism (additional sampling). As a result, the upper limit for the sampling period for suspended solids was also changed from 5% power to until integrated sampling is in service. This change allows operational flexibility to discontinue suspended solids sampling when integrated sampling is initiated. Since integrated sampling is initiated as soon as practical upon feeding steam generators, sampling for suspended solids after that point is unnecessary.

Table 5-6 – Power Operation Feedwater Sampling

Total iron and total copper sampling frequencies have been changed from weekly to continuous using integrated sampling. Action level limit applicability has been changed from >30% power to a power-adjusted rolling average based on thirty days of operation. These two changes are more conservative (more frequent sampling and sampling earlier in power ascension, respectively). Revision 8 also adds a note that units with copper alloys or operating an ion exchange system may use a lower hydrazine to oxygen ratio not less than three times the feed source oxygen concentration. This note is not applicable to SPS.

Table 5-8 – Power Operation Condensate Sampling

Revision 7 allows condensate oxygen to be considered a diagnostic parameter under certain conditions. Revision 8 changes it to a control parameter for the same conditions, and applies an Action Level 1 value of 100 ppb. This change applies more conservatism. Additionally, Revision 8 adds a note to clarify that the Action Level 1 value applies above the mid power value.

As documented in the previous paragraphs, the changes in EPRI Report 3002010645 are either clarifications, add specificity, or add conservatism to the guidance in EPRI Technical Report 1016555. Therefore, the difference between the EPRI reports is acceptable.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2008, an industry assist visit was requested on secondary water chemistry quality and its effects on steam generator condition. Recommendations were made to reduce sodium and other contaminants coming out of the makeup water plant and to improve monitoring and condensate polishing performance to improve secondary water quality. Implementation of recommended practices produced a 90% reduction in maximum steam generator sodium values once the unit increased above 30% power. Also, the time the steam generator sodium was above five ppb was reduced by 94%. Progress was evaluated during an industry peer evaluation in March 2009, and additional corrective actions, including replacement of the On-Line Chemistry Monitoring System instrumentation, were implemented. Continued improvement in secondary chemistry water quality was documented in a 2013 effectiveness review, and the corrective actions were considered effective.
2. In March 2014, Unit 2 was ramped down to 74% as a result of an air line break affecting heater drain level control valves. During the transient, reactor coolant system lithium was low out of the operating band. A lithium addition was made to restore the concentration to specification. Prior to ramping back to 100% power, Chemistry department personnel noted an increasing trend in condensate and steam generator sodium concentrations. The cause was determined to be a condenser waterbox tube leak, and the affected condenser was taken out of service. Condensate polishing returned the sodium concentration to within monitoring limits.
3. In March 2014, Unit 2 reactor coolant system hydrogen went out of specification (OOS) during unit startup. The unit ramp rate was decreased and dilution was lined up to the volume control tank (VCT) inlet to increase the hydrogen concentration. The cause was determined to be sending reactor coolant system blender makeup to the charging pump suction instead of the VCT inlet while performing large reactor coolant system dilutions. Corrective actions included updating the chemistry startup procedure to provide guidance for actions to take to increase reactor coolant system dissolved hydrogen. Also, guidance for mitigating hydrogen decrease during dilutions was added to procedures. These options include increasing VCT hydrogen overpressure, increasing VCT hydrogen percentage, and redirecting reactor coolant system makeup flow to the top of the VCT.

4. In June 2014, it was identified that the EPRI Pressurized Water Reactor Primary Water Chemistry Guidelines do not address monitoring zeolite forming elements such as aluminum, calcium, and magnesium during reactor startup, but the Westinghouse supplement to the EPRI Pressurized Water Reactor Primary Water Chemistry Guidelines recommends monitoring these during heat-up to criticality to detect gross contamination from internal or external sources. Monitoring during heat-up allows for improved detection of these species as they tend to precipitate in the reactor coolant system at operating temperatures and can cause Zircaloy corrosion in fuel. Chemistry procedures were changed to align with Westinghouse guidance for sampling and analyzing aluminum, calcium, and magnesium during heat-up to criticality.

5. In April 2015, Unit 1 lithium concentration was found to be out of specification. Re-sampling was performed, and confirmed the initial sample results. A lithium addition was made to restore concentration to within specification. The cause was determined to be an equilibrium shift in a mixed bed demineralizer due to taking RCS boron to zero ppm, which resulted in the mixed bed removing lithium. Additional guidance was provided in procedures and processes to prevent re-occurrence. This includes not removing all of the boron from the reactor coolant system at the end of cycle to minimize the chemistry impact to the in-service mixed bed. Also, a procedure was revised to require additional lithium monitoring at the end of cycle when concentration is less than five ppm.

6. In December 2015, an effectiveness review of the Chemistry Control Program for Primary Systems Activity (UFSAR Section 18.2.4) and the Chemistry Control Program for Secondary Systems Activity (UFSAR Section 18.2.5) was performed. The aging management activities (AMAs) were evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

7. In May 2016, chemistry procedures were updated to improve shutdown chemistry controls in response to recommendations to incorporate an EPRI interim guideline into procedures. The EPRI interim guideline recommends unit shutdown within eight hours if the feedwater hydrazine to oxygen ratio is less than two when the reactor coolant system is >200F. The shutdown and associated temperature reduction minimize the likelihood and severity of stress corrosion cracking at high temperature and high electrochemical potential when the feedwater hydrazine to oxygen ratio is less than two at operating temperature.

8. In October 2016, a self assessment was performed on primary and secondary chemistry procedures to ensure that critical information from existing and interim industry guidelines was incorporated into procedures. Chemistry startup and shutdown procedures were compared with chemistry program procedures to ensure the appropriate sampling requirements for the applicable modes of operation were captured. The self assessment identified that the chemistry procedures were consistent with existing and interim industry guidelines and included the appropriate sampling requirements at the required times based on plant conditions.

9. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

10. In January 2018, an aging management program effectiveness review was performed of the Chemistry Control Program for Primary Systems (UFSAR Section 18.2.4). Information from the summary of that effectiveness review is provided below:

    Dominion's Chemistry Control Program for Primary Systems maintains the chemistry of primary systems consistent with EPRI Report 3002000505, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” Revision 7. Industry and station operating experience (OE) was reviewed to identify pertinent issues found in the Corrective Action Program from 2006 through 2017 for chemistry events in primary systems such as action level exceedances and adverse trends.

    Sampling frequencies are adjusted based on plant conditions to preclude out of specification conditions. For example, in March 2017, silica concentrations in ‘A’ Boric Acid Storage tank were noted to be significantly higher than the previous month's sample. Chemistry personnel increased the sampling frequency of ‘A’ Boric Acid Storage tank based on the adverse trend in order to quantify the rate of concentration increase to prevent the concentration from going out of specification. An entry was made in the Corrective Action Program to continue trending silica, and issue a work order for pump seal replacement if levels continued to increase. The pump seals contain silica carbide, and failure of the seals could cause the increase in concentration. Since the issue was originally identified, silica levels in `A' Boric Acid Storage tank have decreased, indicating that the pump seals are not degrading.

Plant process and procedure changes are made as necessary based on OE to improve the program. For example in April 2015, a lithium low out of specification (OOS) condition was noted at the end of an operating cycle. A lithium addition was promptly made to return the concentration to within specification and an investigation performed to determine the cause. The cause was determined to be an equilibrium shift in a mixed bed demineralizer due to taking RCS boron to zero ppm, which resulted in the mixed bed removing lithium. Corrective actions included placing steps in a chemistry procedure to increase reactor coolant system lithium sampling when less than five ppm boron and leaving approximately two ppm boron in the reactor coolant system.

Since 2008, occurrences of OOS reactor coolant system lithium and hydrogen have been minimized and were primarily noted during power ramps, off normal RCS configurations, and during challenging conditions such as the end of cycle. In all of the instances, plant personnel corrected the OOS conditions as quickly as plant conditions permitted. A search of plant OE since 2006 did not reveal any primary system or equipment failures attributed to chemistry OOS conditions, demonstrating that the management of chemistry parameters minimizes the effects of aging on plant equipment.

11. In January 2018, an aging management program effectiveness review was performed of the Chemistry Control Program for Secondary Systems (UFSAR Section 18.2.5). Information from the summary of that effectiveness review is provided below:

    Dominion's Chemistry Control Program for Secondary Systems maintains the chemistry of secondary systems consistent with EPRI Report 1016555, “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” Revision 7. Industry and station operating experience was reviewed to identify pertinent issues found in the Corrective Action Program from 2006 through 2017 for chemistry events in secondary systems.

    Sampling frequencies are adjusted based on plant conditions to preclude OOS conditions. Extra sampling is also performed during evolutions which may cause an OOS condition such as power changes. This allows changing conditions in the feedwater such as pH or ETA concentration, or sodium, chloride, or sulfate concentration in the steam generators to be acted upon so that secondary chemistry can be maintained within specifications.

    Iron transport to the steam generators following reactor trips and plant startup conditions has been reduced. Over the last three fuel cycles iron loading into the steam generators has been reduced by 35% in Unit 1 and 27% in Unit 2. This is due to changes in chemistry control and piping replacements using chromium molybdenum alloy piping.

Since 2006, occurrences of OOS chlorides and iron, caused by challenging conditions such as condenser tube ruptures (chlorides) or during reactor trips and plant startups (iron), have been minimized. In all of the instances, plant personnel corrected the OOS conditions as quickly as plant conditions permitted. A search of plant OE since 2006 did not reveal any secondary system or equipment failures attributed to chemistry OOS conditions, demonstrating that the management of chemistry parameters minimizes the effects of aging on plant equipment.

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 loss of material, cracking, 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Water Chemistry* 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.

B2.1.3 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, nuts and washers) and for the threads in the reactor vessel flange.

The *Reactor Head Closure Stud Bolting* program is implemented as part of the ASME Code, Section XI, ISI Program. 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 ISI Programs (Unit 1 and Unit 2) for the fifth 10-year inspection interval are based on the 2004 Edition of the ASME Code, Section XI, with no addenda. Future 120-month inspection intervals will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 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 the U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.65.

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 nuts and washers 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:

- Phosphated surface treatment is used on the studs
- Neolube lubricant is used (precluding the use of molybdenum sulfides)
- Existing studs have tensile strength values that do not exceed 170 ksi

The bolting material used for the reactor vessel closure studs is ASTM SA-540, Grade B24, Class 3. The nuts and washers for closure studs also are SA-540, Grade B24, Class 3. The studs do not include any metal plating.

There are three spare studs, two of which potentially have yield strength values higher than 150 ksi (the Mechanical Specification is 155.5 ksi for those two studs, but no measured values are available), thus presenting a concern for stress corrosion cracking (SCC). The three spare studs have a maximum tensile strength less than 170 ksi, indicating consistency with the RG 1.65 limit identified for the existing studs. Ultrasonic examinations are performed during each ASME Code, Section XI, inspection interval for the closure studs that are being used. For the two spare studs that have values that could exceed the RG 1.65 limit of 150 ksi, the potential for SCC will not be a concern unless those spares are placed in 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.

During the original Unit 2 reactor vessel fabrication, the depth of the vessel flange closure stud holes #36 and #37 exceeded the design length. Westinghouse, as the design authority for the vessel, evaluated the deviation and concluded that the holes, with an insert installed to correct the hole depth, were acceptable to use. This was documented by Engineering to be an original design feature for Unit 2. In order to confirm that no aging effects are occurring for the inserts, an enhancement will require one-time inspection of the bottom plate in vessel flange closure stud holes #36 and #37.

Any indication of degradation in 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.

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 units were licensed prior to the issuance of RG 1.65, Revision 0, in October 1973 and do not have a specification limiting the measured maximum yield strength. Two of the three spare reactor head closure studs do not have measured yield strength less than 150 ksi, thus presenting 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.

Justification for Exception

Four spare reactor head closure studs were procured, one of which was installed in 2015. The reactor head closure stud installed in 2015 had a yield strength less than 150 ksi, and a tensile strength less than 170 ksi. Two of the three remaining stored spare reactor head closure studs potentially have yield strength values higher than the RG 1.65 limit of 150 ksi, thus presenting a potential for SCC. For those two spare reactor head closure studs, potential SCC will not be a concern unless those two spare reactor head closure studs are placed in service. At that time, the potential for SCC will be addressed by the ultrasonic examinations that are performed for the reactor head closure stud bolting in accordance with the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1). The three spare reactor head closure studs have a maximum tensile strength less than 170 ksi, indicating consistency with the limit identified in RG 1.65 for existing reactor head closure studs.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) 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.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to require the performance of a one-time visual inspection of the bottom plates in Unit 2 vessel flange closure stud holes #36 and #37 to confirm that no corrosion, cracking, or degradation is occurring.

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 SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2012, while in the process of cleaning and inspecting the Unit 1 reactor vessel closure studs, it was discovered that one stud (#21) had some minor thread wear on the first seven threads at the bottom of the stud. Engineering was contacted and found the threads were rounded on the outer edges of the male threads. Engineering concluded that the condition did not impact the ability of the stud to carry its load nor impact the ability to thread the stud in or out of the reactor vessel flange. For those reasons, the reactor vessel flange threads were evaluated to be satisfactory and returned to service.

2. In November 2013, while removing the plugs from the Unit 1 reactor vessel flange holes, it was noted that 55 of 58 stud holes were flooded with cavity water which could lead to boric acid corrosion. (The remaining three holes, which had guide studs inserted, used a different sealing mechanism design.) The plug design for the 55 holes was determined to be ineffective. The stud holes were cleaned and inspected in accordance with maintenance procedures, and reassembly of the reactor vessel continued. After the outage, new plugs were fabricated for SPS to replace the failed ones, using a design similar to the (effective) plugs used at North Anna Power Station. No subsequent operating experience has been found to indicate an ongoing concern with flooding in the stud holes.
3. In November 2015, during an ASME Code, Section XI ultrasonic (UT) examination of one Unit 2 reactor vessel closure stud (# 34), the normal and expected UT signal patterns for an acceptable stud could not be obtained. The UT examination of reactor vessel closure stud was not accepted, per ASME Code, Section XI, Category B-G-1. The decision was made to replace the Unit 2 stud, which was completed during that refueling outage.

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, nuts, washers 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Reactor Head Closure Stud Bolting* 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.

B2.1.4 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 are performed to ensure that the corrective actions were adequate and have addressed the identified age-related degradation, as needed.

The *Boric Acid Corrosion* program relies in part on NRC Generic Letter (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 that are outside the scope of the program established in response to NRC GL 88-05 may affect components that are within the scope of subsequent license renewal. Therefore, the scope of monitoring and inspections of this program includes components within the scope of subsequent license renewal that are exposed to an air environment with borated water leakage and 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 ISI pressure tests performed in accordance with ASME Code, Section XI requirements. Specific attributes from WCAP-15988-NP, which are addressed in implementing procedures, are included in the following listing:

- The purpose of the *Boric Acid Corrosion* program is to ensure that the program is established and implemented in accordance with regulatory commitments, and with mandatory and recommended industry requirements.
- Susceptible materials for boric acid corrosion include carbon steel, low-alloy steel, and cast iron; Inconel® alloy base metal and welds (due to PWSCC); and certain copper alloys (containing >15% zinc).

- Locations that are susceptible to boric acid corrosion may be inspected by programs other than the *Boric Acid Corrosion* program. For example, bare-metal visual examinations that are described in the *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) determine the presence of boric acid leakage for the reactor vessel upper head penetration nozzles and the bottom-mounted instrumentation nozzles. Interfaces with the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) include results from visual inspections for loss of material due to boric acid corrosion.
- Visual inspections are performed by qualified individuals who are tasked with performing focused inspections for boric acid leakage. Also, computer-based training is provided to individuals who may observe evidence of boric acid leakage. Evidence of borated water leakage exists as the presence of boric acid crystals or moisture. Discolored boric acid deposits may be an indication of corrosion.
- Routine walkdowns, performed each day by plant operators and radiation protection personnel, will note any evidence of borated water leakage. Additional plant walkdowns are performed by system engineers. Focused inspections are performed during refueling outages by operations and engineering personnel to identify evidence of borated water leakage.
- Findings of borated water leakage are documented in the Corrective Action Program. Results of inspections during refueling outages to identify occurrences of borated water leakage are summarized in an outage report prepared by the boric acid program coordinator. The outage report includes the history of leaking components, and provides a recommendation for actions to remediate the leakage.
- For leakage examinations of borated systems components with external insulation, or for joints that are not visible due to being located under insulation, the surrounding areas of the floor, equipment surfaces, or exposed surfaces of the insulation are examined for evidence of borated water leakage. An initial inspection determines the extent of insulation removal that is required in order to properly perform the examination for evidence of leakage. In some situations (such as for bolted connections which are within the scope of ASME Section XI), removal of insulation may be required in order to perform the borated water leakage inspection. For leakage at an insulated bolted connection in a system that is borated for purposes of reactivity control, the bolting is evaluated by Engineering, as necessary, in accordance with ASME Section XI, subsection IWA 5250 and Code Case N-566-2, “Corrective Action for Leakage Identified at Bolted Connections.”
- The *Boric Acid Corrosion* program identifies sources of borated water leakage, and the pathway and potential targets (i.e., adjacent structures and components) that could be adversely affected by borated water leakage.

- Operating experience has shown that likely locations for borated water leakage include valve packings, body-to-bonnet gaskets, bolted connections, and fittings.
- Leakage that exceeds the screening threshold identified in the *Boric Acid Corrosion* program requires initiation of an engineering evaluation. Engineering evaluations are performed to determine the impact of leakage on the integrity of the borated system pressure boundary or adjacent structures and components. Engineering evaluations determine whether degradation of susceptible structures or components has occurred, whether repair or replacement of structures or components (perhaps using corrosion resistant materials) is needed, or whether the observed condition is acceptable without repair.
- Internal inspections are performed for the containment ventilation system, to detect the presence of boric acid crystals in the containment air recirculation coolers and CRDM coolers (including fans and coils).

NUREG-2191 Consistency

The *Boric Acid Corrosion* program is an existing program and 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 SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2009, during a system pressure test, borated water leakage was observed around the carbon steel flange and bolting of a residual heat removal system heat exchanger, resulting in failure to satisfy a VT-3 inspection. The flange included 48 bolts, 40 of which were replaced with new bolts, washers, and nuts. The remaining eight bolts were determined by engineering evaluation to be acceptable for operation until the subsequent refueling outage. At that subsequent refueling outage, examination of the eight bolts did not identify rejectable indications, and no further corrective action was required.

2. In April 2014, boric acid was found on the packing area, threaded bonnet, and pipe plug of an instrumentation valve. The boric acid was white and dry, and the leak was inactive. There was no apparent degradation affecting the ability of the component to perform its intended function. The boric acid residue was cleaned, and the packing was adjusted, and the valve was returned to service.

3. In May 2015, during a system pressure test, boric acid leakage was identified on a charging system valve. In accordance with ASME Code, Section XI, Subsection IWA-5250, one bolt was to be removed, VT-3 examined, and evaluated in accordance with IWA-3100. Code Case N-566-2 was invoked as an alternative to IWA-5250(a)(2). As stated in the evaluation, per Code Case N-566-2, it was determined that no need existed for removing any of the bolting associated with this valve to perform a VT-3 examination. There was no significant corrosion or visible damage on any of the bolting. There were no identified pathways to nearby components. The valve packing was tightened.

4. In December 2014, the results of a comprehensive self-assessment were documented for the Boric Acid Corrosion Control Program (BACCP). The purpose of the self-assessment was to evaluate the Dominion BACCP against industry standards, strengths, and good practices, and to determine procedural and regulatory compliance. The fleet program documents were assessed to be compliant with regulatory commitments, as well as mandatory and needed NEI 03-08 industry requirements. Other aspects of the evaluation were to determine whether boric acid leakage is promptly identified and documented in the Corrective Action Program, to determine whether boric acid leakage evaluations are performed and documented in a timely manner, to determine whether minor leaks are cleaned and regularly monitored for change in condition, and to determine whether safety significant/excessive leakage is corrected/mitigated in a timely manner. The self-assessment confirmed for SPS that these functions are being completed effectively, and that none of the procedure enhancements suggested as a result of the self-assessment were required for the program to remain successful. No further actions were required to be taken.

5. In December 2015, an effectiveness review of the Boric Acid Corrosion Surveillance Activity (UFSAR Section 18.2.3) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the Boric Acid Corrosion Surveillance Activity (UFSAR Section 18.2.3) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed of the Boric Acid Corrosion Surveillance Activity (UFSAR Section 18.2.3). Information from the summary of that effectiveness review is provided below:

   The Boric Acid Corrosion Surveillance Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the AMA that were reviewed include the extensive visual inspections that are performed for plant components containing boric acid to detect leakage, evaluation of inspection results, repairs and replacements as necessary, and AMA document updates, if required. The occurrences of boric acid leakage leading to corrosion of susceptible components have existed throughout the history of the plant. A 10-year period of condition reports (CRs) and engineering evaluations has been reviewed to identify typical examples of boric acid leakage.

   The Boric Acid Corrosion Surveillance Activity has a stable trend of station personnel identifying and submitting CRs to document boric acid leaks. On average, 125 to150 Boric Acid Corrosion Surveillance Activity-related items are identified during outages. Plant walkdowns during the three most recent refueling outages have identified a consistent number of boric acid leaks from plant components. CR documentation typically includes photographs that have proven to be a valuable aid for establishing corrective maintenance to be performed, and have been beneficial for performing engineering evaluations of the leakage and for accomplishing trending. Boric acid leakage usually affects only components that are not susceptible to corrosion, so minor maintenance and cleaning are sufficient to address the leakage. Occasionally, the extent of corrosion for susceptible components is sufficiently extensive to require component replacement.

Since the Boric Acid Corrosion Surveillance Activity is well-developed, industry operating experience (OE) and EPRI research rarely result in changes being required in the Boric Acid Corrosion Surveillance Activity. One example of industry OE that has been adopted in the Boric Acid Corrosion Surveillance Activity is INPO Event Report IER L3-15-9, “Failure to Evaluate Dry Boric Acid Leak results in Auxiliary Building Contamination.” This INPO Event report was added to the procedure references documenting the review of industry OE during the Boric Acid Corrosion Surveillance Activity procedure revision process.

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 for 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Boric Acid Corrosion* 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.

B2.1.5 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 loss of material and 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, “Materials Reliability Program: Generic Guidance for Alloy 600 Management,” (MRP-126). Bare-metal visual, surface, and volumetric examinations are used to detect the presence of PWSCC. Inspections are performed periodically.

The nickel-alloy components that are inspected due to susceptibility to PWSCC include the reactor vessel bottom-mounted instrumentation nozzles and J-groove welds (ASME Code Case N-722, as incorporated by reference in 10 CFR 50.55a). Other nickel-alloy components that are inspected, but are resistant to PWSCC, include the reactor vessel head penetration nozzles and 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 corrosion 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.

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 and 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 (OE) 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2003, the Unit 1 and Unit 2 reactor vessel heads were replaced and included materials that are resistant to PWSCC.
2. In 2004 for Unit 1, and in 2005 for Unit 2, baseline volumetric inspections were completed for the bottom-mounted instrumentation (BMI) nozzles without any adverse findings. Bare-metal visual examinations are performed every other refueling outage in accordance with ASME Code Case N-722-1, as incorporated by reference in 10 CFR 50.55a. The most recent BMI nozzle visual examinations performed in Fall 2016 for Unit 1 and in Spring 2017 for Unit 2 found no indications of age-related degradation.
3. In October 2016, bare-metal visual examinations were completed for the reactor pressure vessel head penetrations of Unit 1. There were no findings of age-related degradation.
4. In May 2017, bare-metal visual examinations were completed for the reactor pressure vessel head penetrations of Unit 2. There were no findings of age-related degradation.
5. In January 2018, an aging management program effectiveness review was performed of the ISI Program - Reactor Vessel Activity (UFSAR Section 18.2.13). Information from the summary of that effectiveness review is provided in the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1).

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 examinations to detect loss of material and cracking due to PWSCC for Alloy 600/82/182 components or welds on the on the reactor vessel, and to initiate corrective actions. Occurrences identified by 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 that 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 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.

B2.1.6 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 cast austenitic stainless steel (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.

Aging management of potentially susceptible piping and piping components is accomplished through a component-specific flaw tolerance evaluation in accordance with ASME Code, Section XI. Based on the completed flaw tolerance evaluation in WCAP-18258, “Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2,” flaw crack growth remains acceptable for the subsequent period of extended operation.

For valve bodies, based on the results of the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, U.S. Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (May 19, 2000 NRC letter), screening for significance of thermal aging embrittlement is not required. The existing ASME Code, Section XI visual inspection requirements are adequate for valve bodies.

The existing ASME Code, Section XI inspections of the reactor coolant pump casings include a VT-3 visual examination of the internal surfaces whenever a reactor coolant pump is disassembled for maintenance. The existing ASME Code, Section XI visual inspection requirements are adequate for managing the aging effects of reactor coolant pump casings because the original flaw tolerance evaluation performed as part of Code Case N-481 remains bounding and is applicable for the subsequent period of extended operation as detailed in Section 4.7.6.

Reactor vessel internals (RVIs) fabricated from CASS are not within the scope of this program. The *PWR Vessel Internals* program (B2.1.7) manages the aging of CASS reactor vessel RVI components.

NUREG-2191 Consistency

The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing program and is consistent with NUREG-2191, Section XI.M12,Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS).

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that, when performed, the Section XI inspections have been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. During the Unit 1 Spring 2015 Outage, a VT-3 visual exam was performed on the “C” Reactor Coolant Pump casing following removal of the pump for overhaul and turning vane bolt replacement. The VT-3 visual exam was satisfactory with no indications observed. A small quantity of loose debris was found in the discharge nozzle, was satisfactorily removed, and documented in a condition report.
2. During the Unit 2 Fall 2015 Outage, a VT-3 visual exam was performed on the “A” Reactor Coolant Pump casing following removal of the pump for overhaul and turning vane bolt replacement. The VT-3 visual exam was satisfactory with no indications observed.

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 visual inspections that meet ASME Code, Section XI inspection requirements to identify and manage loss of fracture toughness of the susceptible components with regard to thermal aging embrittlement. 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 are 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* 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.

B2.1.7 PWR Vessel Internals

Program Description

The *PWR Vessel Internals* program is an existing condition monitoring program that manages cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of preload for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion (IASCC), 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 1022863, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A),” and EPRI Technical Report 1016609, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals (MRP-228),” to manage the aging effects on the reactor vessel internal components, as supplemented by a gap analysis. The gap analysis includes integration of EPRI Technical Report 3002005349, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines,” (MRP-227, Revision 1), which is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, “Guideline for the Management of Materials Issues”. MRP-227, Revision 1, includes one “mandatory” and four “needed” NEI 03-08 implementation requirements for the *PWR Vessel Internals* program. The guidelines listed in MRP-227, Revision 1, provide an appropriate aging management methodology for the RVI components. The gap analysis also 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”. The inspections of the RVI components are implemented in accordance with EPRI Report 3002005386, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2015 Update (MRP-228, Rev. 2)”.

The Safety Evaluation Report that the NRC issued for the approved version (i.e., MRP-227-A) of MRP-227, Revision 0, dated December 16, 2011, included eight Applicant/Licensee Action Items (A/LAI) that required resolution. Six of those items are applicable for Westinghouse reactors. The six items that require resolution for SPS have been addressed such that no open items exist for the *PWR Vessel Internals* program in preparation for the subsequent period of extended operation.

The *PWR Vessel Internals* program applies the guidance in MRP-227, Revision 1 for inspecting, evaluating, and, if applicable, dispositioning non-conforming RVI components at Units 1 and 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), and “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 following listing identifies the changes that are included in the PWR Vessel Internals program based on MRP 2018-022:

- The corner bolts (Baffle-former Assembly) were added to the population of baffle-former bolts for Primary component.
- Clevis insert bolts (Alignment and Interfacing Components) were elevated from Existing Programs component to Primary component. The scope of this item was expanded to include the clevis insert dowels.
- Thermal sleeves (Alignment and Interfacing Components) were added as a Primary component.
- Radial support keys Stellite wear surface (Radial Support Keys) was added as a Primary component.
- Clevis bearing Stellite wear surface (Alignment and Interfacing Components) was added as a Primary component.
- Fuel alignment pins (Malcomized) (Upper Internals Assembly) were added as an Existing programs component.
- Fuel alignment pins (Malcomized) (Lower Internals Assembly) were added as an Existing programs component.

The initial phase of inspections for RVI inspections began in 2010 for Unit 1 and in 2011 for Unit 2. In 2013 for Unit 1 and in 2014 for Unit 2, RVI inspections were completed for the ‘primary’ components identified for the initial license renewal period. The inspections included the following components:

- Control rod guide tube assembly guide cards
- Control rod guide tube assembly lower flange welds
- Core barrel assembly upper flange weld
- Core barrel assembly lower girth weld
- Baffle-former assembly baffle-edge bolts
- Baffle-former assembly baffle-former bolts
- Baffle-former assembly baffle plates, and indirect effects of void swelling
- Alignment and interfacing components internals hold down spring
- Clevis insert bolting
- Thermal shield flexures

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.

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 or Inspected (Element 3)

1. Procedures will be revised for each reload to summarize the average power density, the heat generation figure-of-merit, and the dimensional parameter for the distance between the active fuel and the upper core plate.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to require the visual inspection (EVT-1) of the control rod guide tube (CRGT) lower flange weld to require that the inspection include 100% of the outer CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal.
3. Procedures will be revised to require the visual inspection (VT-3) of the accessible surfaces for the control rod guide tube support pins and support pin nuts for Unit 1 only (plant-specific component).

4. Procedures will be revised to require the addition of a note indicating that a bolting inspection can be credited only if at least 75% of the total bolt population is examined.
5. Procedures will be revised to require visual inspection (VT-3) for 100% of the baffle-edge bolts that are accessible from the core side.
6. Procedures will be revised to require volumetric (UT) examinations for 100% of accessible baffle-former bolts (including corner bolts) at least every 10 years. MRP-2017-009 states that baseline volumetric (UT) examinations shall be performed no later than 30 EFPY for NSAL 16-1 Tier 2 plants, including the Surry units. The guidance further states that initial baseline UT exams performed prior to 1/1/2018 are acceptable. Examinations were performed in 2010 for Unit 1 and in 2011 for Unit 2. For the Surry units with the down-flow configuration that have <3% indications and no clustering, subsequent UT examinations are performed on a 10-year interval.
7. Procedures will be revised to address expansion criteria when degradation occurs for clusters of baffle-former bolts. MRP 2018-002 identifies expansion criteria as a Needed requirement (per NEI 03-08) to include one-time visual (VT-3) examination of barrel-former bolts if large clusters of baffle-former bolts are found during the initial volumetric (UT) examination.
8. Procedures will be revised to require visual examinations (EVT-1) for 100% of one side (ID or OD) of the circumference for the core barrel upper flange weld, and ¾" of adjacent base metal (minimum 50% examination coverage) (Primary component)
9. Procedures will be revised to require visual examinations (EVT-1) for 100% of the OD surface of the core barrel lower flange weld and ¾" adjacent base metal (minimum 50% examination coverage) (Expansion component)
10. Procedures will be revised to perform inspections of control rod guide tube (CRGT) thermal sleeves as indicated in MRP 2018-027. MRP 2018-027 refers to the Westinghouse NSAL 18-1 recommendation that, based on operating experience (OE) from international PWR plants related to wear of reactor vessel closure head control rod drive mechanism (CRDM) thermal sleeve flanges resulting in control rod stoppage during plant restart operations, a visual inspection should be performed during the next refueling outage after issuance of the NSAL, and during each subsequent refueling outage, for the tops of the CRGTs to determine whether any thermal sleeves have lowered significantly or are in a failed state. For the Surry plants, the guidance is to look for shiny marks on the top edge of the upper guide tube enclosure. Also, during the next under-head inspection, the guidance is to perform a visual inspection of the bottom of the thermal sleeve guide funnels to look for any shiny surfaces on the bottom surface of the guide funnel that would indicate that the thermal sleeve guide funnels have dropped to a point where they are in contact with the top of the guide tube. A visual inspection of thermal sleeve guide funnel elevations is recommended to identify whether any sleeves are noticeably lower than others (Primary component).

11. Procedures will be revised to require visual examinations (VT-3) for the following:
    a. Top and bottom edges of baffle plates to identify misalignment (Primary component).
    b. General condition of the baffle plates to identify warping or void swelling (Primary component).
    c. Surfaces of the upper internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component).
    d. Surfaces of the lower internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component).
    e. Clevis insert bolts and clevis insert dowels (Primary component).
12. Procedures will be revised for contingency tasks to require inspection of the following expansion components if necessitated by relevant indications being found for associated primary components:
    a. Remaining control rod guide tube lower flange welds not inspected as Primary component (EVT-1)
    b. Bottom-mounted instrumentation column bodies (100% of BMI column bodies for which difficulty is detected during flux thimble insertion / withdrawal; VT-3)
    c. Lower support column bodies (25% of column bodies as visible from above the core plate; VT-3)
    d. Barrel-former bolts (100% of accessible bolts, minimum of 75% of the total population; UT)
    e. Lower support column bolts (100% of accessible bolts, minimum of 75% of the total population; UT)
13. Procedures will be revised to require that the inspections for the radial support keys and clevis inserts are to include the Stellite wear surfaces (Primary component, MRP 2018-022).
14. Procedures will be revised to require visual inspections (VT-3) of the guide cards in at least 37 of the 48 control rod guide tubes, and will include associated acceptance criteria. Guidance from WCAP-17451-P, “Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections,” and MRP 2018-07, “Transmittal of NEI 03-08 Needed Guidance to Address Accelerated Guide Card Wear Operating Experience (OE) Discussed in NSAL-17-1,” will be included for the inspection of control rod guide cards.
15. Procedures will be revised to require visual examinations (EVT-1), and will include associated acceptance criteria, for 100% of one side of the accessible surfaces of the core barrel lower girth weld and ¾” of adjacent base metal (minimum 50% examination coverage). (Primary component)

16. Procedures will be revised for contingency tasks to inspect the following expansion components if necessitated by relevant indications being found for associated primary components, and will include associated acceptance criteria:
    a. Core barrel upper, middle, and lower axial welds (100% of weld length – 50% examination coverage; EVT-1)
    b. Core barrel upper girth weld (100% of weld length – 50% examination coverage; EVT-1)
    c. Core barrel lower flange weld (100% of weld length – 50% examination coverage; EVT-1)
    d. Lower support forging (25% of bottom surface; VT-3)
    e. Upper core plate (25% of accessible surfaces; VT-3)

Monitoring and Trending (Element 5)

17. A procedure for visual examinations will be revised to identify the examiner qualifications which are applicable for EVT-1 examinations.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2010, VT-3 and UT examinations of baffle-former bolts were performed for Unit 1. The entire population of 1088 bolts was inspected. There were four findings. There were two bolts that were non-inspectable using UT due to deformation at the points on the hex heads that affected the back wall signal. However, reviews of the UT signals concluded there were no flaws and the VT-3 results showed no degradation. In general, the VT-3 examination results were satisfactory. One bolt had unacceptable VT-3 results due to a missing locking bar weld on one end, but that was evaluated to be an original fabrication condition, and no further action was recommended. The UT result for that bolt was satisfactory. One bolt was rejectable for UT results due to a flaw in the head-to-shank region, but had an acceptable VT-3 result.

   Baffle-edge bolt VT-3 examinations also were performed in 2010 for Unit 1. 936 accessible edge bolts were inspected. The only degradation that was noted for baffle-edge bolts was a missing weld on one end of the locking bar on one bolt which was determined to be an original fabrication condition. No further action was recommended.

2. In May 2011, VT-3 and UT examinations of baffle-former bolts were performed for Unit 2. The entire population of 1088 bolts was inspected. The VT-3 examination results were acceptable, but there were two reportable indications from the UT examinations. The visual examination for those two non-adjacent bolts showed no structural damage to the bolt head, locking bar or

locking bar welds. The two indications were bounded by existing analysis which confirmed structural integrity and safety function of the reactor internals assembly. Baffle-edge bolt VT-3 examinations also were performed in 2011 for Unit 2. 936 accessible edge bolts were inspected. No degradation of baffle edge bolts was noted.

3. During refueling outages in 2012, control rod guide tubes (CRGT) assembly guide card inspections were performed for Units 1 and 2. The CRGTs had been replaced in Unit 1 in the mid-1980s; the CRGTs in Unit 2 were the original components. The inspection results in 2012 confirmed acceptable results for guide card wear. The nominal guide card slot width for 15x15 fuel is 0.277-inch. The maximum measured value for the slot width for Unit 1 was 0.2851-inch: for Unit 2, the value was 0.2850-inch. The nominal value for the second monitored parameter of ligament length is 0.1859-inch. The minimum measured value of ligament length was 0.165-inch. These differences of no more than 11% indicate no concern for guide card wear.

4. In May 2014, an examination of the Unit 2 radial support keyway at 270 degrees identified an area of material deformation. By visual estimation, the groove-like indication reduced the surface area by less than 5%. Due to no indication of current wear, it was concluded that minimal wear had occurred over an extended period of operation. An engineering evaluation determined that this slight reduction in surface area was insignificant and acceptable.

5. In May 2014, three relevant indications were noted on the reactor pressure vessel cladding. The first indication involved an impression of a fastener nut, and the second indication was the subject nut which was still in the vessel, but was subsequently removed. The third indication was an impact point where a component or part had come into contact with the cladding. The indication did not appear to contain any cracks or flaws that would have the possibility to grow. There was no distortion or displacement of the surrounding structure. The observed condition was evaluated to be acceptable without further action.

6. In September 2014, Westinghouse issued Technical Bulletin TB-14-5, “Reactor Internals Lower Radial Support Clevis Insert Cap Screw Degradation”. The bulletin recommended that during the next 10-year reactor vessel exam when the core barrel is removed, a VT-1 should be performed on the clevis bolts. The Augmented Inspection Plan was revised to include the recommended NDE examination.

7. In August 2016, Westinghouse provided a summary of industry operating experience regarding baffle-former bolts. NSAL-16-1, “Baffle-former Bolts,” designated SPS as a Tier 2b plant. For such plants, NSAL-16-1 recommended that records of previous UT inspections of bolting be reviewed to identify any indication for the onset of clustering in the bolt failure patterns. Clustering is defined as three or more adjacent bolts or a total number of failures in a single baffle plate greater than 40% of the total number of bolts on that baffle plate. Unit 1 has a record of one UT bolting failure identified by UT examination, and Unit 2 has two. Therefore, a cluster failure concern (three or more adjacent failures) is not an issue for either unit.

8. In August 2016, Westinghouse issued Technical Bulletin TB-16-4, "Fuel Alignment Pin Malcomized Surface Degradation," after becoming aware of industry operating experience indicating degradation of lower core plate (LCP) and upper core plate (UCP) fuel alignment pins with a malcomized surface. As a result, those alignment pins have been added to the scope of inspections for the reactor vessel internals.

9. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

10. In November 2017, as part of oversight review activities, the Reactor Vessel Internals Inspection Activity (UFSAR Section 18.2.15) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

11. In April 2018, MRP letter 2018-010 recommended that plants currently in a refueling outage or scheduled for an outage visually examine the general condition of the top of the Control Rod Guide Tubes (CRGTs) for any shiny rings which is indicative of a thermal sleeve guide funnel having dropped to a point of being in contact. Operating experience at a non-U.S. Westinghouse-designed plant indicated thermal sleeve wear due to contact with the CRGT. A degraded thermal sleeve has been shown to interfere with the movement of the control rod. Additional information regarding this operating experience was provided in Westinghouse Nuclear Safety Advisory Letter NSAL-18-1, "Thermal Sleeve Flange Wear Leads to Stuck Control Rod," in July 2018. During the refueling outage for Unit 1 in Spring 2018, visual inspections were performed for the top of the CRGTs and for the bottom of the thermal sleeve funnels to look for shiny surfaces which indicate wear. No indications were found.

12. In January 2018, an AMA effectiveness review was performed of the Reactor Vessel Internals Inspection Activity (UFSAR Section 18.2.15). Information from the summary of that effectiveness review is provided below:

    The Reactor Vessel Internals Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. The Reactor Vessel Internals Inspection Activity includes visual inspections and non-destructive examinations of components that comprise the reactor pressure vessel internals. Key elements of the activity that were reviewed included identification of reactor internals structural components to be inspected, inspection frequencies and techniques, evaluation and documentation of inspection results, repair/replacement tasks, industry initiatives, and program updates. The reviews were based on guidance from MRP-227-A per the requirements of NEI 03-08, and UFSAR Section 18.2.15 as well as license renewal commitment #14. Condition Reports (CRs) were reviewed for a 10-year period (July 2006-June 2016) to identify possible occurrences of age-related degradation for the reactor vessel internals.

The initial examinations performed for the Reactor Vessel Internals Inspection Activity found degradation only for a few of the baffle-to-former bolts. Those findings were evaluated to not jeopardize the integrity of the reactor internals. There were no findings of degradation for other structural components in the reactor internals.

Relevant industry documents that provide a basis for the Reactor Vessel Internals Inspection Activity include WCAP-17096, “Reactor Internals Acceptance Criteria Methodology and Data Requirements,” WCAP-14577, “License Renewal Evaluation: Aging Management for Reactor Internals,” WCAP-17451, “Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections,” and NSAL-17-1,”Guide Tube Guide Card Wear Attributed to Ion Nitride Rod Cluster Control Assembly.” The Fleet Lead for the Reactor Vessel Internals Inspection frequently participates in industry meetings and performs reviews of industry OE summaries to remain aware of potential needs to revise the scope, frequency, or techniques to be used for reactor internals examinations. There has been no need to make any such changes. Compliance with the guidance of MRP-227-A is maintained.

The above examples of operating experience provide objective evidence that the *PWR Vessel Internals* program includes activities to perform volumetric and visual inspections to identify cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of preload for the reactor vessel internals 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 loss of intended function.

Conclusion

The continued implementation of the *PWR Vessel Internals* 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.

B2.1.8 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 the aging effect of wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The *Flow-Accelerated Corrosion* program is consistent with the Virginia Power response to NRC Generic Letter 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 inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

The *Flow-Accelerated Corrosion* program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ 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) results from thickness measurements 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; inspections are scheduled to support a planned approach such that the components wall thickness will be managed until replacement can be scheduled.

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.

NUREG-2191 Consistency

The *Flow-Accelerated Corrosion* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M17, Flow-Accelerated Corrosion.

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):

Scope of Program (Element 1) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to include a re-evaluation of systems currently excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time to ensure that an adequate basis exists to justify continuing this exclusion.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

<u>FAC Operating Experience</u>

1. In April 2009, FAC inspections were performed during the refueling outage using the ultrasonic testing technique. Those inspections found that two 1.5 inch nominal OD sections of piping in the main steam system had minimum wall thickness below 65% of nominal, and required replacement. That replacement effort was completed using FAC-resistant piping prior to resuming power operation. A review of the inspection history for the associated lines and for parallel trains was conducted, and a scope expansion of six extra main steam lines was identified. The completion of the follow-on scope expansion and evaluation demonstrated an ongoing focus within the *Flow-Accelerated Corrosion* program for susceptible components.
2. Industry Operating Experience: In August 2009, industry OE described a steam piping failure that caused a plant shutdown. A FAC review revealed a similar small-bore piping arrangement at Unit 2. No similar finding was identified for Unit 1. Accordingly, those pipe sections were replaced during the subsequent Unit 2 refueling outage.
3. In November 2009, as part of the *Flow-Accelerated Corrosion* program, an 18" diameter section of feedwater system piping was UT inspected and found to have inadequate wall thickness, thus requiring replacement during the current refueling outage. A work order was completed to replace the piping section using CrMo material prior to resuming power operation.
4. In November 2010, after a main steam trip valve was removed to allow replacement due to erosion at the lower gasket seat, Engineering performed a visual FAC inspection of the upstream and downstream components. Wall thinning was found on the downstream elbow. The three inch carbon steel elbow was replaced using CrMo material.
5. In April 2011, several components on a ten inch condensate polishing line were UT inspected during the refueling outage as part of the *Flow-Accelerated Corrosion* program. The measured wall thickness for a nozzle was projected to be below the minimum allowable wall thickness prior to the next refueling outage, thus requiring replacement or repair during the current outage. Weld buildup repairs were completed for the nozzle and associated elbow prior to resuming power operation.

6. In December 2015, an effectiveness review of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The results of that review indicated that license renewal references were not included in the Flow Accelerated Corrosion Activity procedures. Resolution was achieved by revising the controlling procedures for the Flow Accelerated Corrosion Activity to provide references to the technical reports or pertinent section of the license renewal application for the license renewal commitments.

7. In November 2016, a fleet self-assessment of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was completed. The assessment included a review, with industry peers, of standard processes for the Flow Accelerated Corrosion Activity to identify whether they were as efficient and effective as possible. No Areas for Improvement were identified, but it was determined that efficiencies could be gained by implementing more modern technologies. Opportunities for procedure enhancements also were identified. Since 2016, FAC Manager software has been placed in service to automate the process of transferring component evaluation results into CHECWORKS-SFA™. Procedure enhancements continue to be processed.

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In November 2017, as part of oversight review activities, the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

10. In January 2018, an AMP effectiveness review was performed of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16). Information from the summary of that effectiveness review is provided below:

    The Flow Accelerated Corrosion Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. The activity uses ultrasonic testing (UT) to perform wall thickness measurements of piping that is susceptible to FAC in either single or two-phase flow conditions. Visual inspections of the internals of plant piping systems are performed as the equipment is opened for other repairs and/or maintenance to detect flow accelerated corrosion (FAC) degradation. Condition Reports (CRs) for a 10-year period (July 2006-June 2016) have been reviewed to identify examples of degradation resulting from FAC.

    Reviews of FAC inspection results determine whether the component needs to be replaced during the outage in which it was inspected, or whether the remaining wall thickness and measured wear rate justify continued operation until the next inspection opportunity or planned replacement. Inspection results are used to determine whether examination frequencies are appropriate, and whether additional components need to be inspected or replaced to address the extent of degradation in similar components. The application of both visual and UT inspections have been confirmed to be appropriate. CRs are monitored by the Flow Accelerated Corrosion activity owner to identify potential impacts for the Flow Accelerated Corrosion Activity.

    Industry Operating Experience (OE) is discussed during fleet conference calls, and reviews are performed to determine whether a revision of the Flow Accelerated Corrosion Activity is needed. As an example, an OE item from a U.S. nuclear power plant describes an extraction steam drain line failure that caused a unit shutdown. A FAC OE review identified a similar small-bore piping arrangement at Unit 2. Accordingly, those pipe sections were replaced during the subsequent refueling outage. NRC generic communications also are monitored to identify the need for any changes to the Flow Accelerated Corrosion Activity or additions for the scope of inspections.

Erosion Operating Experience

11. In October 2006 the 14" combined recirculation line for the Unit 2 Main Feed Pumps was discovered to have four through-wall, pin-hole leaks, near the top of the pipe in a bend section near the condenser. An evaluation noted that, while FAC issues in this line were addressed under an earlier design change in 2003 and FAC-resistant piping was installed, cavitation-erosion scenarios were not adequately considered or addressed in that design change. In May 2008, as part of a design change to address several problems in feedwater recirculation flow and pump operations, changes were made in the design and arrangement of this affected line, and a diffuser was added to mitigate the cavitation-erosion that was occurring in the recirculation line pipe bend.

12. In December 2007, an NDE inspection was performed on a service water line (Cu-Ni piping) to a safety-related HVAC chiller to monitor degradation (erosion) as a result of previous failure evaluations. The NDE inspection provided additional wall thinning information until a design change could be implemented. The results of NDE indicated that wall thinning due to erosion (likely cavitation) was continuing, however the readings at that time were above the minimum allowable acceptance criterion. Measured wall loss rates indicated that replacement or repairs were needed in the next six to 12 months. A design change was completed in 2008 to install different pumps and globe valves that significantly reduce the flow velocity.

13. In May 2008 during a preventive maintenance activity, UT thicknesses measurements were taken on the Auxiliary Feedwater pumps' recirculation piping downstream of the orifices at Unit 2. This was based upon an event at Millstone in 2006, where a pinhole leak was discovered in the mini-flow recirculation lines downstream of the restricting orifice (RO). Although there was no through-wall leakage for this piping, the results revealed wall thinning. One Unit 2 line was below the code minimum, so the affected piping was replaced in May 2008. Unit 1 NDE inspections were found acceptable.

14. In December 2008, an engineering inspection of a main control room chiller revealed condenser tube erosion, but no leaks. Per Engineering recommendation, Plastocor coating was placed on the tubes of ‘A’ main control room chiller in June 2009, and on the tubes of ‘C’ main control room chiller in July 2010.

The above examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program includes activities to (a) identify all susceptible piping systems and components; (b) develop FAC predictive models to reflect component geometries, materials, and operating parameters; (c) perform analyses of models and, with consideration of operating experience, select a sample of components for inspections to identify wall thinning caused by flow-accelerated corrosion to be managed for susceptible components within the scope of subsequent license renewal, and to initiate corrective actions. 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, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Flow-Accelerated Corrosion* 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.

B2.1.9 Bolting Integrity

Program Description

The *Bolting Integrity* program is an existing condition monitoring program that manages cracking, loss of material and loss of preload of safety-related and non safety-related closure bolting for pressure-retaining components within the scope of subsequent license renewal, except for the reactor vessel closure head studs that are addressed in the *Reactor Head Closure Stud Bolting* program (B2.1.3).

The program refers to NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants". NUREG-1339 includes guidance from EPRI report NP-5067, "Good Bolting Practices Volume 1 (Large Bolt Manual)," and from EPRI report NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants".

The listing for EPRI NP-5769 mentions an exception noted in NUREG-1339 for safety-related bolting. That exception is applicable for bolting used in pressure-retaining applications, and indicates that experimentally–verified fastener material properties and fracture mechanics evaluations should be used to ensure that safety-related fasteners are unlikely to be susceptible to stress corrosion cracking. EPRI Report 1015336 is applicable for the Bolting Integrity program, and states that applicable material properties should be confirmed with the fastener manufacturer. EPRI Report 1015336 includes guidance for preventing or mitigating stress corrosion cracking by the proper selection of bolting. Table B-1 of EPRI Report 1015336 lists appropriate bolting, and is a reference for the bolting design standard at SPS.

The *Bolting Integrity* program includes the following additional considerations from NUREG-1339:

- 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, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," (Table 4-9) is included in the *Bolting Integrity* program as indicated by the following tasks performed by the program:

- Examine all 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
- Specify proper lubricant and torque values during maintenance.
- Examine code material requirements, bolt and nut markings, and material identification.

Recommendations from EPRI Report 1015337, "Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints," 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. Neolube N-7000 is the lubricant approved for use.

The absence of high-strength pressure-retaining closure bolting precludes the need for volumetric inspections for those components.

Potentially submerged pressure-retaining bolting is associated with submersible pumps (primarily sump pumps) for the balance of plant, the emergency service water pumps located at the Low-Level intake Structure, and the recirculation sump screens located in Containment.

- Submerged bolting for the sump pumps will be inspected opportunistically when the inaccessible bolting is made accessible during maintenance activities. In this case, bolt heads are inspected when made accessible, and bolt threads are inspected when joints are disassembled. A procedure enhancement will be developed to include a requirement to inspect the bolt heads and threads. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts heads and threads is inspected. If the required sample opportunities do not occur, bolting integrity will be demonstrated by other means such as trending pump vibrations or performing plant walkdowns to determine whether the sump pumps are maintaining sump levels.
- Submerged bolting inspection for an emergency service water pump will be performed at least once per ten years when the intake structure screenwell is dewatered.
- Closure bolting inspections for the recirculation sump screens and the service air/ instrument air sub-systems will be performed on a sampling basis consistent with the guidance provided for the sump pumps. [Note: only the air sub-systems require aging management since the hydrogen gas sub-system is not in the scope of components requiring aging management for SLR, and the nitrogen gas sub-system does not contain pressure-retaining bolting requiring inspection].

For the sampling inspections listed above, inspections shall be completed for at least 20% of the population, up to a maximum of 25 bolt heads and threads, for each material/environment combination. The sample size can be reduced to 19 per unit if there are no pertinent differences between the units. The reduced total number of inspections is acceptable based on the following:

- Water chemistry requirements for the two units are identical, and the operating conditions are similar. Any deviations from established water chemistry guidelines are corrected promptly.
- The raw water used for the two units comes from the same source so the probability of differences in susceptibility to aging mechanisms such as microbiologically-influenced corrosion is low.

Operating experience for the two units indicates no significant difference in aging effects for the integrity of pressure-retaining bolting.

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/aging effect combination are required for each inspection that did not meet the acceptance criterion. For a two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same material, environment, and aging effect combination. The additional inspections are to be completed within the same interval (e.g., refueling outage or 10-year inspection interval). If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the Corrective Action Program.

Inspections and tests are 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 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 for SPS manage aging effects associated with safety-related and non safety-related structural bolting:

- *ASME Section XI, Subsection IWE* program (B2.1.29)
- *ASME Section XI, Subsection IWF* program (B2.1.31)
- *Structures Monitoring* program (B2.1.34)
- *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35)
- *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program (B2.1.13)

The *External Surfaces Monitoring of Mechanical Components* program (B2.1.23) describes the inspections for non-ASME pressure-retaining closure bolting.

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):

Detection of Aging Effects (Element 4)

1. Procedures will be revised to provide inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 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 feet to four 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.

Detection of Aging Effects (Element 4)

2. Procedures will be revised for inspections of pressure-retaining closure bolting in locations that preclude detection of joint leakage, such as in submerged environments or where the piping system contains air for which leakage is difficult to detect. The inspections will be performed to detect loss of material. A requirement will be included to inspect bolt heads when made accessible, and bolt threads if joints are disassembled. At a minimum, in each 10-year interval during the subsequent period of extended operation, inspections shall be completed for a representative sample of at least 20% of the population, up to a maximum of nineteen, for each material/environment combination.

Corrective Action (Element 7)

3. A new procedure will be developed to provide guidance for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination is not corrected by repair or replacement, thus requiring that additional inspections be performed. The number of additional inspections will be 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/aging effect combination are required for each inspection that did not meet the acceptance criterion. For a two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same

material, environment, and aging effect combination. The additional inspections are to be completed within the same interval (e.g., refueling outage or 10-year inspection interval). If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the Corrective Action Program.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2008, the flange bolting on both sides of a Unit 2 service water valve was found to be corroded to the point that the threads were not distinguishable. The joint appeared to be leak-free, but the bolts were in need of replacement. The bolting replacement was completed and the valve was returned to service.
2. In April 2009, during an ASME Code, Section XI pressure test, leakage was noted at a bolted connection on a Unit 1 residual heat removal heat exchanger. ASME Code, Section XI, IWA-5250(a)(2) specifies that if leakage occurs at a bolted connection, one of the bolts shall be removed for a VT-3 examination. The removed bolt had evidence of degradation, thus requiring that all remaining bolting be removed for a VT-3 examination. There are 48 closure bolts. Forty bolts were removed for inspection. Eight bolts could not be removed. Thirty-six of forty bolts removed were rejectable. The forty removed bolts were replaced. An engineering evaluation was written to justify operation for one additional cycle with the eight old bolts in place. A work order was written to replace the eight bolts that could not be removed during the 2010 outage. However, no additional corrective action was required since the inspection during the 2010 outage found no wastage of the eight bolts and no boric acid leakage on the heat exchanger.
3. In December 2013, EPRI provided notification of Code Noncompliance associated with a Performance Demonstration Initiative (PDI) supporting implementation of ASME Code, Section XI, Appendix VIII, Supplement 8, bolting exams. Applicability involved Class 1 components containing category B-G-1 bolting. Determination of potential impacts required a review of calibration standards used for examination to verify notch size and location, and that the material, size, and geometry are similar to the bolting to be examined. The stud and bolt calibration standards were determined to be acceptable and in full compliance.

4. In November 2015, Engineering performed VT-1 examinations of the Unit 2 ‘A’ steam generator primary manway bolting. Each manway has 16 studs and nuts. One stud had corrosion and possible wear on a non-threaded segment. An engineering evaluation determined that the stud was acceptable for re-use.

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 loss of intended function.

Conclusion

The continued implementation of the *Bolting Integrity* 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.

B2.1.10 Steam Generators

Program Description

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 [tubes], plugs, sleeves, 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 other primary-side and secondary-side components. The visual inspections of the 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. Tube-to-tubesheet welds do not require inspection because the H* alternate repair criteria have been permanently approved to eliminate those hot-leg and cold-leg welds as reactor coolant pressure boundaries.

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. Procedures implement 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.

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 Technical Specifications; the Maintenance Rule (10 CFR 50.65); EPRI 3002007571, “Steam Generator Integrity Assessment Guidelines”; EPRI 3002007572, “PWR Steam Generator Examination Guidelines”; EPRI Technical Report (TR) 1022832,” PWR Primary-to-Secondary Leak Guidelines”; and 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 *Steam Generators* program includes plant-specific steam generator DAs that identify existing and potential degradation mechanisms and associated aging effects that could impact the integrity of the steam generators. The DA identifies inspection techniques and 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, tubing and primary-side inspections are typically performed every other 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 unaddressed mechanism that could adversely affect steam generator primary-side or secondary-side integrity, as well as the effects of any chemistry excursions and transients that could affect existing degradation mechanisms.

The DA indicates that primary-side inspections include video/visual examinations, specifically including:

- All 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

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 steam generator, and the subsequent removal of sludge deposits help avoid tube degradation. Sludge mapping occurs when the steam generator is inspected, and inspections for remaining foreign material are performed after sludge lancing is completed. Sludge lancing is typically performed at least every other refueling outage. Steam drum inspections and Deposit Minimization Treatment are performed less frequently. The *Water Chemistry* program (B2.1.2) also monitors and controls reactor water chemistry and secondary water chemistry for the steam generators consistent with EPRI 3002000505, “PWR Primary Water Chemistry Guidelines,” and EPRI 3002010645, “PWR Secondary Water Chemistry Guidelines,” as a preventive measure.

The Technical Specifications include the following requirements, which 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 steam generator tube degradation.

The *Steam Generators* program detects flaws in tubes, tube plugs, and tube support plates needed to maintain tube integrity. Non-destructive examination techniques are used to inspect tubing materials to identify tubes that may need to be removed from service or repaired in accordance with the Technical Specifications. The program uses volumetric examinations for the tubes, and visual inspections for the other primary and secondary components. The program provides criteria for the qualification of personnel, specific inspection techniques, and the associated acquisition and analysis of data, including procedures, probe selection, analysis protocols, and reporting criteria. Assessment of tube integrity and plugging or repair criteria of flawed tubes is in accordance with plant technical specifications and the program implementing procedures. Tube plugs and tube support plates with indications of aging are evaluated for corrective actions in accordance with the Corrective Action Program and the *Steam Generators* program.

Condition 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 technical specifications and NEI 97-06 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 original steam generators were replaced for Unit 2 in 1980 and for Unit 1 in 1981. The purpose of the replacement was to address degradation caused by corrosion-related phenomena. Steam generator tubes had been plugged as a result of tube denting caused by corrosion of the tube support plate in the annular spaces between tubes and the tube support plate. The steam generator project involved replacing the lower section of each steam generator and refurbishing the upper section. The replacement steam generators incorporated Alloy 600 thermally-treated tubes to improve reliability and minimize aging.

NUREG-2191 Consistency

The *Steam Generators* program is an existing program and 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2008, inspections of tubing in the Unit 2 ‘B’ steam generator found indications of primary water stress corrosion cracking in a sampling of the hot leg tube ends in that generator. As a result, the scope was expanded to include inspections for 100% of the hot-leg tube ends for the three steam generators. Plugging was performed for one tube in the ‘B’ steam generator, two tubes in the ‘C’ steam generator, and three tubes in the ‘A’ steam generator.
2. In November 2009, preventive tube plugging in the Unit 2 ‘A’ steam generator was performed due to the presence of an irretrievable foreign object adjacent to a tube that was determined by eddy current testing to have 50% through-wall wear. Three additional tubes were plugged and stabilized due to the presence of the loose part. By plugging those three tubes and eliminating their susceptibility for leakage due to the loose part, a “cage” was formed to prevent the loose part from damaging other nearby tubes.

3. In November 2009, seven tubes were plugged in the Unit 2 ‘C’ steam generator due to not having performed the required tube expansion in the tubesheet for compliance with the NRC-approved alternate repair criteria. Interim alternate repair criteria had been submitted and approved by the NRC prior to this outage. Six additional tubes were plugged due to actual wear, or as a preventive measure, to address the effect of a loose part at the baffle plate.

4. In April 2015, foreign material was found in a Unit 1 steam generator. Attempts to retrieve the foreign material were unsuccessful due to the location being inaccessible. A wear scar was evident on the closest tube, but there was no damage on other nearby tubes. The closest tube was plugged as a precaution. An engineering evaluation determined that foreign material could remain in the steam generator since the foreign material was small and stationary.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In November 2017, as part of oversight review activities, the Steam Generator Inspections Activity (UFSAR Section 18.2.18) AMA owners confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activities commitments. No gaps were identified by the review.

7. In December 2017, a fleet self assessment was completed for the Steam Generator Inspections Activity (UFSAR Section 18.2.18). The assessment team verified that the Steam Generator Inspections Activity is being implemented in accordance with fleet and site procedures, and found that there were no programmatic issues. There were no non-compliance issues with NEI 03-08, NEI 97-06, and the EPRI Steam Generator Management Program guidelines. As part of the assessment process, steam generator operating experience (OE) was provided to the assessment team members for review to ensure that the OE was being appropriately incorporated into the Steam Generator Inspections Activity. In addition, Degradation Assessments (DA) were reviewed to ensure that Industry OE was being incorporated into the inspection plan for SPS. No issues were identified.

8. In July 2018, the program health report for the Steam Generator Inspections Activity (UFSAR Section 18.2.18) was issued with no programmatic issues identified. The evaluation of operating experience (OE) did not identify any actionable items for the program. The OE reviews include INPO IERs, WANO OE, NRC communications, and vendor information letters or technical bulletins.
9. In January 2018, an aging management program effectiveness review was performed of the Steam Generator Inspections Activity (UFSAR Section 18.2.18). Information from the summary of that effectiveness review is provided below:

   The Steam Generator Inspections Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed included the selection of components to be inspected, the inspections of those components, the evaluation of inspection results, repairs/replacements of degraded components, and AMA document updates. Records review identified pertinent issues found in the Corrective Action Program from 2006 through 2017 for age-related degradation of components within the scope of license renewal. Engineering reports from 2004 to 2017 were reviewed to confirm that inspections were performed at appropriate frequencies, and that corrective actions were implemented consistent with the observed age-related degradation.

   A living Lifecycle Management Plan is maintained that identifies inspection plans for the next five years based on degradation, risk ranking, and internal/industry operating experience, as well as Technical Specifications and applicable EPRI guidance. In 2009, stress corrosion cracking (SCC) was identified in the tube ends as well as the top-of-tubesheet. To ensure reliable detection of SCC, the inspection scope was expanded to include a larger percentage of the existing tubes using improved volumetric technology to find these indications. The steam generators have performed well with little signs of degradation and almost no growth in anti-vibration bar (AVB) wear. There has been no significant primary-to-secondary leakage in the steam generators since they were replaced. Water chemistry meets or exceeds industry standards.

   Industry operating experience has been, and continues to be, reviewed to identify any relevant issues for steam generator integrity. Any changes that are determined to be necessary for the Steam Generator Inspections Activity are discussed and explained in the DA document for each unit. Categories for the OE include the following:

   - Unexpected inspection results
   - Foreign material
   - Issues and automated data analysis errors for eddy-current testing
   - Tube plugging errors and plug installation problems
   - Unexpected tube support configuration
   - Corrosion experience

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 (e.g., wall thinning), and reduction of heat transfer for steam generator components 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Steam Generators* 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.

B2.1.11 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 loss of material, reduction of heat transfer, flow blockage, and cracking of the piping, piping components, and heat exchangers identified by the Virginia Electric and Power Company responses to NRC GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” The program is comprised of the aging management aspects of the Virginia Electric and Power Company 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, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. Additionally, recurring internal corrosion (RIC) is addressed in the Corrective Action Program through design modifications that have replaced materials more susceptible to degradation in raw water with materials that are less susceptible to degradation in raw water. This program includes enhancements to the guidance in GL 89-13 that address operating experience such that aging effects are adequately managed.

The open-cycle cooling water system includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13.

The guidelines of GL 89-13 are utilized for the surveillance and control of biofouling for the open-cycle cooling water system. Procedures provide instructions and controls for chemical and biocide injection. Periodic sampling procedures monitor free available oxidant at heat exchangers. In addition, periodic flushing, cleanings and/or inspections are performed for the presence of biofouling.

Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities. Additionally, safety-related piping segments are examined (i.e. ultrasonic testing) periodically to ensure that there is no significant loss of material, which could cause a loss of intended function.

Routine inspections and maintenance ensure that corrosion, erosion, sediment deposition (silting), and biofouling do not degrade the performance of safety-related systems serviced by open-cycle cooling water. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the aging effects of the internal surface coatings.

Aging effects associated with elastomers and flexible polymeric components in the open-cycle cooling water system are managed by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25).

The *Buried and Underground Piping and Tanks* program (B2.1.27) manages the aging effects of external surfaces of buried and underground piping and components. The external surface of the aboveground raw water piping and heat exchangers is managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23). The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging effects of internal surface coatings including those of metallic surfaces coated with Carbon Fiber Reinforced Polymer that is used as a pressure boundary.

NUREG-2191 Consistency

The *Open-Cycle Cooling Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M20, Open-Cycle Cooling Water System.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

1. Section XI.M20 of NUREG-2191, Open-Cycle Cooling Water, indicates that testing intervals can be adjusted to provide assurance that equipment will perform the intended function between test intervals, but should not exceed five years. The *Open-Cycle Cooling Water System* program takes exception to the NUREG-2191 requirement to perform testing of the recirculation spray heat exchangers (RSHXs) at an interval not to exceed five years.

<u>Justification for Exception</u>:

As described in the plant responses to GL-89-13, heat transfer performance testing of the RSHXs is not performed due to system configuration that would require significant design modifications to support such testing. Alternatively, the RSHXs are visually inspected to confirm the absence of indications of degradation. To further reduce the potential for degradation, the internal environment of the RSHXs and the portion of the connected piping that cannot be isolated from the RSHXs is maintained in dry layup (i.e., maintained in an air environment) and the internals of the portion of the inlet piping that is not in dry layup is maintained in wet layup (i.e., a treated water environment that has been chemically treated to maintain a basic pH) to minimize corrosion. The open-cycle cooling water side of the RSHXs are periodically flow tested and visually inspected.

The plant GL 89-13 responses stated that the RSHXs would be flow tested and visually inspected every fourth refueling outage (i.e., every six years) and that the testing and inspection intervals may be modified based on the results of further testing. Based on the results of further testing, the RSHXs are currently flow tested and visually inspected at an interval of eight refueling outages (i.e., every twelve years).

The change in frequency to once every eight refueling outages for RSHXs flow testing and visual inspection was evaluated by Engineering. The evaluation included a review of prior operating experience (flow testing and visual inspection results). Prior flow test results documented between 1997 and 2010 were reviewed. The test results identified little or no blockage, with the exception of a test performed in 2003. The 2003 results revealed 5% blockage, which was still less than the 10% blockage acceptance criteria. RSHXs service water inlet and outlet piping cleaning and inspection are performed on a frequency consistent with RSHXs flow testing. A review of prior piping inspection results between 1996 and 2014 showed the piping to be in satisfactory condition. Although coating defects and areas of corrosion were identified during the piping inspections, the RSHXs were capable of performing their intended function. Required coating and weld repairs were entered in the Corrective Action Program.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program.
2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation.
3. The internal lining of 24 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation.

Parameters Monitored and Inspected (Element 3)

4. Procedures will be revised to remove reference to the carbon steel piping that was replaced and will include the replacement material.

5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement.

Detection of Aging Effects (Element 4)

6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the *Structures Monitoring* program (B2.1.34) that are consistent with the requirements of ACI 349.3R.

Monitoring and Trending (Element 5)

7. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering.

8. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results.

Acceptance Criteria (Element 6)

9. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses.

10. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions.

11. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing “hoop” bands or rust staining from such reinforcing elements.

Corrective Actions (Element 7)

12. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation.

13. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 2001, a through wall leak was identified in an eight inch carbon steel control room chiller service water supply line. A through wall leak in similar piping occurred again in September 2005. In May 2006, volumetric inspections measurements identified a location in an eight inch carbon steel control room chiller service water supply line that was less than the minimum allowable wall thickness. A design change was implemented, which replaced the eight inch carbon steel piping with copper-nickel piping.
2. Between August 2007 and July 2009, biofouling of the control room chillers Y-strainers and rotating strainers occurred on multiple occasions. The initial cause was thought to be insufficient backwash flow to the rotating strainers during periods of elevated service water temperatures with one control room chiller operating. Procedure changes were implemented to start an additional pump and backwash the rotating strainers when differential pressure reaches one psid. Further clogging of the Y-strainers resulted in compensatory actions being established. These measures included increased monitoring of control room chiller and service water operating parameters when service water temperature was greater than 80ºF, weekly flushing of control room chiller service water lines, and securing the chiller and cleaning the chiller suction strainers when pump suction pressure approached the minimum required net positive suction head.

In July 2009, repeated clogging of the control chiller suction Y-strainers occurred. Additional compensatory measures included more frequent flushing of the control room chiller service water piping, and running a minimum of two control room chillers to minimize system transients, which was determined to exacerbate biofouling of the strainers. In the fall of 2009, a modification was completed that provided additional chemical (biocide) injection into the service water system downstream of the rotating strainers and upstream of the Y-strainers to control biofouling. Chemical injection has proven effective in reducing biofouling of the Y-strainers and associated piping.

3. In October 2009, following sampling of the service water side of the component cooling heat exchangers, chemistry personnel determined the free available oxidant (FAO) readings were below minimum acceptable values, which could jeopardize control of biofouling in the system. The chemical injection pump settings were adjusted to restore the pump discharge pressure. Samples taken following adjustments revealed that the FAO levels were acceptable.
4. In February 2010, augmented volumetric inspections of the component cooling heat exchanger service water supply and discharge piping identified piping wall thicknesses that were less than minimum allowed. A weld repair was performed and the calculation of record was updated to reflect the results of the wall thickness readings. Pipe stresses were determined to be within code allowable. Subsequent wall thickness measurements taken following repairs were acceptable.
5. In January 2012, during the performance of a license renewal inspection of a component cooling heat exchanger, pitting, defective coatings, barnacles, and river debris were identified in the heat exchanger. Corrective actions included replacement of a manway, removal of debris from the heat exchanger, coating repairs, and performance of a weld repair. Inspections performed in April 2013 and February 2016 also identified needed weld repairs to the heat exchanger end bell. A surface examination and system pressure test were performed satisfactorily following weld repairs.
6. In October 2013, during surface preparation and weld inspections, a through wall leak was observed in the 42 inch service water piping adjacent to the motor-operated valve supplying service water to the component cooling water heat exchangers from the ‘1B’ condenser water box tunnel. The cause of pipe wall thinning was determined to be non-application of the pipe internal coating. Historically, the motor-operated valve exhibited seat leakage since original installation. In an effort to control leakage, a blank and a hose were used to divert the leakage. As a result, the piping at the blank was unable to be properly coated. Over time, the lack of coating resulted in significant wall loss. Corrective actions included replacement of the valve with a design which would minimize valve leakage, weld repairs to the piping, and internal coating of the piping. A post-weld surface examination and system pressure test were performed satisfactorily.

7. In November 2013, three through wall leaks were identified in the 42 inch piping upstream of the motor-operated valve supplying service water to the component cooling water heat exchangers from the ‘1D’ condenser water box tunnel. The leaks were identified following sand blasting of the piping in preparation for application of internal coating. Weld repairs were performed to correct the deficiencies. A surface examination and system pressure test were performed satisfactorily subsequent to the repairs.
8. Between September 2015 and September 2016, five leaks occurred in the service water system due to cracking of fiberglass piping. The leaks were either repaired or new piping segments installed in accordance with the work order process. The fiberglass piping in the service water system may be replaced with corrosion resistant material such as copper-nickel as part of a time-phased program.
9. In December 2015, an effectiveness review of the Service Water System Inspections Activity (UFSAR Section 18.2.17) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.
10. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMA was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
11. In September 2017, as part of oversight activities, of the Service Water Inspections Activity (UFSAR Section 18.2.17) it was noted that commitments for the low level intake screenwell (LLIS) and emergency service water pump suction end bell cleaning/inspections were not being performed and documented consistent with the original License Renewal commitment. The License Renewal commitments for the LLIS cleaning and pump inspections were originally incorporated into the procedure that dewatered the LLIS. The recent license renewal cleaning/inspections were performed by divers using a recurring work activity without dewatering the LLIS. A corrective action was initiated for engineering and outage planning to resolve the inconsistency. It was determined that the cleaning and inspection commitments were satisfactorily completed without dewatering the LLIS. Update of the maintenance strategy and associated documents to allow performance of the license renewal commitments with or without dewatering the LLIS is in progress.

12. In January 2018, an aging management program effectiveness review was performed for the Service Water System Inspections Activity (UFSAR Section 18.2.17). Information from the summary of that effectiveness review is provided below:

    The Service Water System Inspections Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the AMA that were reviewed include the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports from 2004 to 2016 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of open-cycle cooling water system components within the scope of license renewal.

    The key aspects of the *Open-Cycle Cooling Water System* program involve controlling biofouling, testing critical heat exchangers, inspecting and cleaning the system, and designing with robust materials. The program is implemented using an active Service Water System Inspection and Maintenance Program and has a well-established Generic Letter 89-13 Program. These programs govern the approach to compliance with the Nuclear Regulatory Commission (NRC) Generic Letter 89-13, Service Water Problems Affecting Safety-Related Equipment. The Program is inspected every three years by the NRC using Inspection Procedure 71111.07, Heat Sink Performance. The most recent inspection did not identify any findings. Additionally, station effectiveness is assessed by implementing INPO SOER 07-2, Intake Cooling Water Blockage every three years. The assessment reviews operating experience, condition reports, and equipment performance for the three year period. The most recent assessment, completed in September 2016, concluded that open-cycle cooling water equipment has been performing satisfactorily.

    Over the summers of 2007 through 2009, a series of events involving an influx of biological growth from the James River prompted the creation of the Service Water Excellence Plan. The plan has resulted in numerous improvements designed to greatly reduce the adverse effects of biofouling and aging. For example, a biocide injection system has been installed to reduce biological growth, key pieces of safety-related piping have been converted to corrosion and fouling resistant materials, and new monitoring and flushing procedures have been instituted. More recently, since entering the first period of extended operation, the interior of the large diameter open-cycle cooling water piping has begun to be lined with carbon fiber reinforced polymer (CFRP). Surry Power Station is first in the industry to employ this technology. It is predicted that the CFRP will add 50 years of effective service life to the asset. The biocide injection point on the safety-related service water piping will also be relocated to maximize effectiveness.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and internal fouling of components, has occurred on several occasions. Corrective actions have been taken previously, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to flow blockage and loss of material in the open-cycle cooling water system. The physical modifications completed or scheduled, and enhancements to operating practices and system design to improve OCCW system resistance to recurrence of internal corrosion are noted below:

The Open-Cycle Cooling Water (OCCW) System program will manage aspects of RIC in the service water system and the circulating water system that are within the scope of the program. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage loss of material on the internal surfaces of service water system and circulating water system piping that has been lined or coated. The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25) will manage loss of material on the internal surfaces of service water system and circulating water system piping not covered by NRC Generic Letter 89-13.

Flow Blockage:

> Flow blockage in OCCW system piping and components is managed by periodically monitoring control room chiller Y-strainer differential pressure and periodically flushing affected piping flow paths. During times when service water temperatures are elevated, above 80°F, the operations surveillance frequency of monitoring service water suction pressure and rotating strainer differential pressures are increased to intervals as short once every 4 hours and piping flush frequency increased to once daily. As a preventive measure, biocide injection points have been added downstream of the rotating suction strainers and the biocide injection has significantly reduced hydroid attachment and growth. A plant modification is in progress to add additional injection points to the upstream portion of the service water rotating strainers.

Loss of Material in Uncoated Steel Piping:

> Loss of material has resulted in recurrent wall thinning and through wall leakage in service water piping in uncoated steel service water piping associated with main control room chillers. Replacement of uncoated steel piping with corrosion resistant copper-nickel piping reduced the susceptibility of the OCCW systems to recurring internal corrosion. There has been no documented recurring internal corrosion on the control room chillers copper-nickel piping or other copper-nickel service water system piping within the scope of subsequent license renewal.

Loss of Material in Copper-Nickel Alloy Heat Exchanger Tubing:

> Recurring internal corrosion (loss of material) was experienced in the copper-nickel alloy heat exchanger tubing at and beyond the tube sheet for the main control room chiller condensers, including a condenser that had been recently replaced. The affected heat exchanger components have been cleaned and coated with a protective epoxy coating with the coating extending six inches into the heat exchange tubes. The Corrective Action Program apparent cause evaluation identified that the heat exchanger management program did not require flow to be maintained for an extended period in new 90-10 copper-nickel alloy heat exchangers to permit a protective oxide film to form on the tubes prior to the placement of the heat exchangers into a stagnant wet lay-up condition. Implementing documents have been modified to incorporate this lesson-learned. After epoxy coating and modification of wet layup practices, there has been no documented recurring internal corrosion in the control room chiller condenser copper-nickel alloy tubing at and beyond the tube sheet.

Loss of Material in Coated Steel Piping and Heat Exchanger Channel Heads:

> Corrosion-resistant Carbon Fiber Reinforced Polymer (CFRP) liner will be installed in the 96-inch circulating water inlet piping, and 24-, 30-, 36-, 42-, and 48-inch service water supply from the circulating water system to the recirculation spray and supply to the component cooling water heat exchangers. The CFRP system is designed to take the place of the existing carbon steel pipe and will form a repaired pipe within the existing piping that is capable of meeting the design requirements of the station piping. The appropriate relief has been granted for this repair by the NRC. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging of CFRP in the OCCW systems. For epoxy coated piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging of the existing epoxy-coated steel piping.

The above examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program includes activities to perform surveillance and control, heat exchanger testing, and routine inspection and maintenance to identify loss of material, reduction of heat transfer, flow blockage, and cracking of the piping, piping components, and heat exchangers within the scope of subsequent license renewal, as identified by the Virginia Electric and Power Company responses to NRC GL 89-13, 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 manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Open-Cycle Cooling 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 for 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 the aging effects of 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 molybdate-based, chromate-based, glycol-based, phosphate-based, or hydrazine-based chemistry controls to minimize the age-related degradation of components exposed to a closed treated water environment. The chilled water system uses pure water corrosion control. 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 nineteen components per population at each unit 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 nineteen inspections.

Where the sample size is not based on the percentage of the population, the total number of inspections is reduced to nineteen components per population at each unit. The reduced total number of inspections is acceptable because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Both use the same corrosion inhibitors and chemistry methods for closed treated water systems. Past power uprates were implemented for both units at approximately the same time. Operating experience for each unit demonstrates no significant difference in aging effects of closed treated water systems between the units.

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 at both Unit 1 and Unit 2. 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 are 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, surface coverage, presence of protective coatings, and cleaning processes.

NUREG-2191 Consistency

The *Closed Treated Water Systems* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M21A, Closed Treated Water Systems.

Exception Summary

The following program element(s) are affected:

Parameters Monitored or Inspected (Element 3) and Acceptance Criteria (Element 6)

1. NUREG-2191 indicates that the specific water chemistry parameters monitored and the acceptable range of values for these parameters are in accordance with the EPRI Technical Report 1007820, “Closed Cooling Water Chemistry Guideline,” which is used in its entirety for the water chemistry control or guidance. An exception is being taken to use EPRI Report 3002000590, “Closed Cooling Water Chemistry Guideline,” Revision 2.

<u>Justification for Exception:</u>

There are two differences between EPRI Technical Report 1007820 and EPRI Report 3002000590 that are applicable to chromate-based treatment programs. For chromate-based programs, EPRI Report 3002000590 allows a higher chromate concentration upper limit than EPRI Technical Report 1007820. EPRI Technical Report 1007820 cites a study that discussed the potential for degradation of carbon pump seals at chromate levels greater than 500 ppm. EPRI Report 3002000590 also references the study, but goes on to note that while the reference was subsequently withdrawn, it is retained in EPRI Report 3002000590 because it addresses the potential of carbon seal wear. EPRI Report 3002000590 further recommends that plants using carbon pump seals at chromate concentrations in excess of 500 ppm should monitor their carbon pump seals to verify no abnormal wear.

With the exception of the neutron shield tank cooling water system and the emergency diesel generator cooling water system, chromate concentration is controlled to less than 500 ppm in the other systems with chromate control. There are no pumps in the neutron shield tank cooling water system. The emergency diesel generator cooling water system pumps have carbon seals. The diesel generators are run monthly for maintenance, at which time any pump seal leaks would be evident. Additionally, a 12-year maintenance procedure provides instructions for replacement of cooling water pumps if the seals have active leaks. Operating experience shows that there has not been any age-related degradation issues with carbon pump seals in the emergency diesel generator cooling water system. An industry diesel owner's group has documented that cooling water pump seal leakage increases gradually in the event of failure. Therefore, any seal degradation would likely be detected before failure during the monthly diesel runs. Since the carbon pump seals are monitored for leakage as part of regular maintenance, the recommendation of EPRI Report 3002000590 to monitor the seals is met, and the difference between the EPRI Reports is acceptable.

Also for chromate control programs, the lower limit of the acceptable pH range of EPRI Report 3002000590 (7.5) is outside the lower limit of the range in EPRI Technical Report 1007820 (8.0). However, the lower limit of the pH is procedurally controlled to 8.0, which is consistent with the limit in EPRI Technical Report 1007820. Therefore, the difference between the EPRI Reports is acceptable.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 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 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 component internal inspections, accessible surfaces will be inspected, subject to a minimum 20% surface area examination coverage. 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. The surface to be examined should be clean and free of corrosion products, slag, dirt, grease, and scale, loose or cracked paint or any foreign material that interferes with examination results. If protective coatings are present, the condition of the coating will be documented.

Detection of Aging Effects (Element 4)

2. A new procedure will be developed to specify that 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, 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 nineteen components per population at each unit 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.

Monitoring and Trending (Element 5)

3. A new procedure will be developed 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. A new procedure will be developed 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 at both Unit 1 and Unit 2. 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2010, during eddy current inspections of the turbine lube oil cooler tubes, rusty material was noted in the tubes and on the channel heads. The eddy current inspection revealed no corrosion damage to the tubes. A sample of the material was analyzed using scanning electron microscopy. One of the samples was likely from a metal repair material and another was an iron oxide. The material was cleaned out and engineering personnel evaluating the issue determined that no further actions were required.
2. In May 2011, trending of molybdenum concentration in the bearing cooling system indicated an increased loss of corrosion inhibitor. The Chemistry department extrapolated the trend to provide an estimated time by which a chemical addition would need to be performed. Chemistry department personnel recommended performance of a drop test on the bearing cooling heat exchangers due to past operating experience with tube leaks. Drop tests were performed and identified tube leaks in bearing cooling heat exchanger ‘1A’ originating from the open-cycle cooling side. Corrective actions resulted in the plugging of seven leaking tubes.

3. In May 2012, during replacement of a component cooling valve, a license renewal as-found inspection was performed on the valve and associated piping. Mild accumulation of sediment and debris were noted. The observations were noted on the License Renewal As-Found Inspection Form, the condition report, and the associated work order. Engineering evaluated the condition, and determined the accumulation was acceptable and that system function was not impaired.

4. In October 2013, elevated impurity levels in the charging pump cooling water system were identified by industry peers. Chloride ingress into the system was identified as a persistent issue. The cause was determined to be service water intrusion from the intermediate seal coolers. The chloride concentration has been proactively managed below the EPRI limit by feed and bleed. Additionally, non-destructive examination performed in 2012 to assess piping wall thicknesses in the system, provided evidence that the feed and bleed strategy was minimizing corrosion progression. The recent rate of chloride ingress is minimal, as evidenced by the fact that feed and bleeds have only been necessary on an approximately yearly basis.

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, 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.

B2.1.13 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 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 has been developed consistent with the following:

- ASME B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)”
- ASME B30.11, “Monorail Systems and Underhung Cranes”
- ASME B30.16, “Overhead Hoists (Underhung)”
- NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants”

The extent of cranes, hoists, monorails, and rigging beams within the scope of subsequent license renewal includes those previously evaluated as part of compliance with NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” as well as other equipment handling systems operating over safety-related equipment. Also within the scope of subsequent license renewal are fuel and equipment handing systems that handle 'light' loads over fuel and safety-related equipment.

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is implemented through procedures that are based on the ASME B30 series standards, and relies upon visual examinations (general visual, VT-3, VT-1) and limited volumetric (ultrasonic thickness measurement) or surface examinations 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. The installed cranes do not use high strength bolts that are susceptible to stress corrosion cracking (SCC). Inspection frequencies are consistent with the recommendations within the ASME B30 series of standards. For handling systems that are infrequently in service, such as those only used during refueling outages, periodic annual inspections may be deferred until just prior to use. Cranes and hoist inspections do not include inspection of the building structures that support the cranes. The building structures are examined by the *Structures Monitoring* program (B2.1.34).

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 enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1), Parameters Monitored/Inspected (Element 3), and Acceptance Criteria (Element 6)

1. Procedures will be revised to specify visual inspections for the effects of general corrosion, deformation, cracking, and wear on the rails in the rail system.

Scope of Program (Element 1)

2. Procedures will be revised to specify visual inspections for general corrosion, deformation, cracking, wear and loose or missing fasteners and other conditions indicative of loss of bolting preload for the new fuel transfer elevator.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2015, an effectiveness review of the Inspection Activities – Load Handling Cranes and Devices Activity (UFSAR Section 18.2.10) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements.

   Aspects of the aging management of the new fuel transfer elevator were questioned. Engineering was tasked to review the aging evaluation on the new fuel transfer elevator and found that difference in the aging management of the new fuel transfer elevator compared to other load handling equipment is due to the aging management requirements for the submerged portions of the new fuel transfer elevator. The aging evaluation performed by engineering resolved the aging management requirements for load handling cranes and devices in a submerged environment with no program changes or updates required.

2. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

3. In March 2017, during a Fuel Building walk down, one of the studs that attach hold-down pads for the Fuel Building bridge crane rails to the pool wall was found to be sheared off flush with the hold-down pad, and two studs were bent with shiny marks indicating wear. A further walkdown and visual inspection of the remaining studs was performed with no further damage having been found. Sixty-one clips are installed on this rail. The bent studs and their associated hardware were intact. Based on the large amount of intact clips on the south crane rail, one broken stud was determined to have a negligible effect on the crane rail. The rail and the crane were determined to be capable of performing their design function in this condition.

4. In November 2017, as part of oversight review activities of Inspection Activities – Load Handling Cranes and Devices Activity (UFSAR Section 18.2.10), it could not be confirmed that AMA inspections relating to the manipulator cranes had been performed and the inspections addressed the manipulator cranes consistent with the AMA commitments. A gap was identified during the process of the evaluation involving inconsistency between the aging management of the manipulator cranes at both units and the requirements of the safety evaluation report and of the AMA summarized in Inspection Activities – Load Handling Cranes and Devices Activity (UFSAR Section 18.2.10). The issue resulted in a condition in which documentation of inspections of the manipulator cranes and the auxiliary hoists for the manipulator cranes during an extended interval could not be confirmed. The following corrective actions were completed:

   - Procedures to inspect the manipulator cranes were developed
   - A work order to perform the inspection of the manipulator crane prior to the next refueling cycle was prepared
   - The maintenance strategy for the manipulator cranes was modified to reestablish periodic inspections to prevent recurrence

   Additional action was also taken to establish the extent of condition with respect to documentation of the completion of other license renewal AMA results.

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 examinations (general visual, VT-3, VT-1) and limited volumetric (ultrasonic thickness measurement) or surface examinations to identify cracking, loss of material, and loss of preload on bolted connections for cranes and hoists within the scope of subsequent license renewal, 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, 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.

B2.1.14 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 based on the response to NRC Generic Letter 88-14, “Instrument Air Supply Problems,” and utilizes 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.” 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 component internal surfaces for signs of loss of material due to corrosion will be performed. The effects of corrosion and presence of contaminants are detected during quarterly surveillances, and opportunistic inspections. The procedures and maintenance activities for these inspections will include specific inspection acceptance criteria. The opportunistic inspections of accessible internal surfaces of components will provide assurance that the systems within the scope of subsequent license renewal will perform their intended function.

Visual inspection results from the opportunistic inspections will be compared to previous results to ascertain if adverse long-term trends exist. The monitoring methods are effective in detecting the applicable aging effects and prevent significant age-related degradation. Deficiencies are documented in the Corrective Action Program and evaluations are performed for test or inspection results that do not satisfy established criteria.

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 enhancement(s) 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. Procedures will be revised to perform opportunistic visual inspections of internal surfaces of compressed air system components downstream of the dryers to verify the effectiveness of the compressed air system control of moisture (dewpoint) and particulate. Visual inspection results will be compared to previous results to ascertain if adverse long-term trends exist. Deficiencies will be documented in the Corrective Action Program and evaluations performed for test or inspection results that do not satisfy established criteria as defined in the applicable procedures.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 1986, oil free, rotary screw type, air cooled replacement service air compressors were installed to replace the originally installed reciprocating air compressors. The compressors are more reliable and double the capacity of the originally installed reciprocating compressors. The air compressors provide both service air and instrument air during normal operation.

2. In August 1990, the refrigerant type air dryers were replaced with heatless reactivated desiccant air dryers. The design of the dryer was developed in consideration of NRC Generic Letter 88-14. The dew point performance of the desiccant dryers and associated filters provide an air quality that meets the requirements of the ANSI/ISA Standard S7.3. The new dryers maintain a pressure dew point significantly lower than the original dryers and are equipped with oil coalescing pre-filters and particulate after filters. The pre-filters remove water, oil, and particulate 0.6 microns and larger. The after filters remove particulate (including desiccant fines) 0.9 microns and larger.

3. In July 2006, obsolete filters, located immediately downstream of the Containment instrument air supply, were replaced with new filters that increased the level of filtration to bring the normal Containment Instrument Air supply to the three micron or better criteria to meet requirements of ANSI/ISA Standard S7.3. The new coalescing high efficiency filter ensures liquid carryover is minimized (lowering dew point), maximizes time between filter changes, and minimizes the pressure drop across the filters.

4. In March 2011, an effectiveness review was performed of condition reports, apparent cause evaluations, and root cause evaluations. Also included was a review of periodic test results measuring air quality at several points throughout the instrument air system. System air quality, as measured at the discharge of the air dryers and after filters, is maintained within the requirements of ANSI/ISA-S7.0.01-1996 standard. Air quality at the inlet supply to safety-related and critical components that are needed to shutdown and maintain the plant in a safe condition is maintained within the specifications of the equipment vendors. The search went back to 2007 and there were no issues related to periodic monitoring of air quality. There was no evidence of hydrocarbon or moisture related problems in the instrument air system.

5. Operating experience was reviewed over a 10-year period to ensure that the operating experience discussed in NUREG-2191 is bounding, i.e. that there is no unique plant-specific operating experience in addition to that described in NUREG-2191. Periodic air quality tests were performed that confirmed system dewpoint and particulate were maintained within specified parameters. In addition, during the 10-year period from 2006 through 2016 no loss of component intended function was reported thus ensuring the system will perform its intended function for the subsequent period of extended operation.

The above examples of operating experience provides objective evidence that the *Compressed Air Monitoring* program includes activities to perform air quality checks at various locations to identify loss of material to be managed on the internal surfaces of select 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, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Compressed Air Monitoring* 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.

B2.1.15 Fire Protection

Program Description

The *Fire Protection* program is an existing condition and performance monitoring program comprised of functional tests and visual inspections. The program manages:

- Loss of material for fire-rated doors, fire damper housings, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- Loss of material (spalling) or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- Hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- Loss of material, change in material properties, cracking/delamination, and separation for non-elastomer fire barrier penetration seals, fire stops, fire wraps, and coatings cracking/delamination, and separation
- Loss of material and cracking for aluminum seismic gap covers

This program includes fire barrier inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, fire damper housings, and periodic visual inspection and functional tests of fire-rated doors to demonstrate that their operability is maintained. The program also includes periodic inspections and functional tests of the halon systems and low-pressure carbon dioxide systems.

The *Fire Protection* program requires visual inspections of not less than 20% of the penetration seals every 12 months, such that 100% of the seals are inspected every five years. The program specifies visual inspections of the fire barrier walls, ceilings and floors in structures within the scope of subsequent license renewal every five years. The visual inspections of fire barriers include determining the condition of fire wraps every eighteen months. The eighteen month frequency also is applicable for visual inspections of fire doors and damper assemblies. Periodic functional checks are performed on the fire doors.

The program will also provide for aging management of external surfaces of the halon systems and low-pressure carbon dioxide fire systems components that are within the scope of license renewal through periodic visual inspections for corrosion that may lead to loss of material. The program includes functional testing of the halon systems and low-pressure carbon dioxide fire suppression systems components in accordance with the Technical Requirements Manual.

Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for proper disposition.

NUREG-2191 Consistency

The *Fire Protection* program is an existing program and is consistent with NUREG-2191, Section XI.M26, Fire Protection.

Exception Summary

None

Enhancements

None

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2010, an original K-10 mortar fire barrier in the Turbine Building/Auxiliary Building pipe tunnel was determined to be damaged and non-functional. The instance was corrected by providing a new installation of Rectorseal BIO K-10+ Fire Rated Mortar having a 3-hour rating, and providing the required train separation in accordance with 10 CFR 50, Appendix R, Section III.G.2(a).
2. In July 2012, during the performance of a periodic maintenance procedure for inspection (functional check) of a swinging safety-related special purpose fire door, the gum rubber seal on the latch side of the door frame was found to be deteriorated. The seal was replaced as determined by engineering evaluation.
3. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

4. In January 2018, an aging management program effectiveness review was performed for the Fire Protection Program Activity (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

   The Fire Protection Program Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the Fire Protection Program Activity that were reviewed include the inspection of fire doors, fire barriers, fire detection, fire suppression, fire protection system integrity, RCP oil collection system, and Appendix R equipment as well as the evaluation of inspection results, repairs/replacements, corrective actions, and AMA document updates. A review of Engineering inspection result reports from 2006 to 2017 confirmed inspections were conducted at appropriate intervals and corrective actions were taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of fire protection components within the scope of license renewal.

   Problems that included equipment obsolescence, false alarms, operator distraction, and potential single point failures were arising with the old fire detection system, which resulted in installation of a new fire detection system in 2015. Not all of the old fire panels were replaced. A new design change is currently being developed to address obsolescence of the remaining fire panels as well as make enhancements to the new fire detection system.

5. In March 2018, the NRC completed a triennial fire protection inspection. One finding was determined to have very low safety significance (Green). The finding involved failure to adequately protect fiberglass pipe that is susceptible to fire damage and required for safe shutdown. This finding was treated as a non-cited violation and closed. The subject pipe was replaced on both units with part fiberglass protected by Pyrocrete and part copper-nickel. Both portions of replacement pipe will withstand a three-hour fire.

The above examples of operating experience provide objective evidence that the *Fire Protection* program includes activities to perform visual inspections to identify cracking, loss of material, spalling, hardening, shrinkage and loss of strength for structures and 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 are 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 will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Fire Protection* 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.

B2.1.16 Fire Water System

Program Description

The *Fire Water System* program is an existing condition monitoring program that manages loss of material, flow blockage, and loss of coating integrity for in-scope water-based fire protection systems. This program manages aging effects by conducting periodic visual inspections, flow testing, and flushes. 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”. There are no nozzle strainers, glass bulb sprinklers, fire pump suction strainers, or foam water sprinkler systems within the scope of subsequent license renewal.

The *Fire Water System* program will include testing a representative sample of the sprinklers prior to fifty years in service with additional representative samples tested at 10-year intervals. Sprinkler testing will be performed consistent with the 2011 Edition of NFPA 25, “Standard For The Inspection, Testing and Maintenance of Water-Based Fire Protection Systems,” Section 5.3.1. The fifty year in-service date for sprinklers is October 26, 2021.

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, were designed and installed with a configuration and pitch to allow draining. With the exception of two locations, Engineering walkdowns confirmed the as-built configuration that allows draining and does not allow water to collect. Corrective actions have been initiated for the two locations to verify a flow blockage condition does not exist and to restore the two locations to original configuration requirements that allow draining and do not allow water to collect. After corrective actions, portions of the water-based fire protection system that have been wetted, but are normally dry, will not be subjected to augmented testing and inspections beyond those required by NUREG-2191, AMP XI.M27, Table XI.M27-1.

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 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 exist. The status of the fire pumps is indicated in the Main Control Room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the control room.

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 are performed by personnel qualified in accordance with 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 conducted. The number of increased tests is determined in accordance with the site's corrective action process; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections are completed within the interval (i.e., 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. The additional tests will include at least one test at the other unit on site with the same material, environment, and aging effect combination.

In addition to piping replacement, actions will be taken to address instances of recurring corrosion due to microbiological induced corrosion. Low Frequency Electromagnetic Technique (LFET) or similar scanning technique will be used for screening 100 feet of accessible 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 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 visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

Aging of the external surfaces of buried and underground fire main piping is managed by the *Buried and Underground Piping and Tanks* program (B2.1.27). Loss of material and cracking of the internal surfaces of cement lined buried and underground fire main piping are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

Aging of the fire water storage tank bottom surfaces exposed to oil soil are managed by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17).

Acceptance criteria, corrective action recommendations, and training/qualification of individuals involved in fire water storage tank internal coating inspections are implemented by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

NUREG-2191 Consistency

The *Fire Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI M27, Fire Water System.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

1. The fire water storage tanks are insulated carbon steel tanks located in an outdoor environment. NUREG-2191, AMP XI.M27, Table XI.M27-1 and note 10 recommends the insulated external surfaces of fire water storage tanks be inspected for signs of degradation on a refueling outage interval for signs of degradation. This would require insulation removal each refueling cycle. Therefore, inspections of the external carbon steel surfaces of the fire water storage tanks will be performed on a 10-year frequency during the subsequent period of operation.

Justification for Exception:

The line item in NUREG-2191, Section XI.M27, Table XI.M27-1, for water storage tank external surfaces recommends the inspection guidance of NFPA, 2011 Edition, Section 9.2.5.5, which requires inspection of insulated tank surfaces. NFPA, 2011 Edition, Section 9.2.5.5, does not provide specific inspection guidance for corrosion of metallic surfaces under insulation in an outdoor air environment. NUREG-2191, Section XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, element 4, provides inspection guidance for corrosion under insulation for insulated carbon steel tanks located in an outdoor environment. NUREG-2191, Section XI.M29, Table XI.M29-1, recommends a 10-year frequency for corrosion under insulation during the subsequent period of operation.

2. NUREG-2191, Table XI.M27-1, note 10 recommends main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and control valves on an annual or refueling outage interval. Surry Power Station will perform the main drain tests on twenty percent of the standpipes and risers every refueling cycle.

Justification for Exception

As indicated by NUREG-2191 Table XI.M27-1, note 10, access for some inspections is feasible only during refueling outages which are scheduled every eighteen months. Main drain tests on twenty percent of the standpipes and risers every eighteen months provide adequate information to determine the condition of the fire water piping is maintained consistent with the design basis.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. Procedures inspection guidance will be revised to require replacement of any sprinkler that shows any of the following: leakage, corrosion, physical damage, loading, painting unless painted by the sprinkler manufacturer, or incorrect orientation. Sprinklers at the following locations will be added to the test scope: The Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building.
2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner. For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed.
3. Procedures will be revised to specify:
    a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow.
    b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action.
    c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination.
    d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)

4. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests.

Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

5. Procedures for hydrant flushing will be revised to require fully opening the hydrant and fully flowing the hydrant for no less than one minute and until foreign material has cleared. In addition, procedures will be revised to observe draining of the hydrant barrel and also require the barrel be pumped dry should it not drain within 60 minutes. Hydrants outside the protected area that are within the scope of subsequent license renewal will be added to the flush scope.
6. The *Fire Water System* program will be revised to periodically inspect the insulated exterior surfaces of the fire water tanks on a 10-year frequency during the subsequent period of operation. Insulation is removed to provide a minimum inspection population of 25 one-square foot samples. The samples will be distributed in such a way that inspections occur on the tank dome, near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring.
7. Procedures for mainline strainer flushing will be revised to require flushing until clear water is observed after each operation or flow test. In addition to flushing after operation, the Radwaste Facility mainline strainer will require an inspection every five years for damaged and corroded parts.
8. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected.

9. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. 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 visual internal inspections of piping by removing a hydraulically remote sprinkler, 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 visual internal inspections of piping by removing a hydraulically remote nozzle, 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 visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

Detection of Aging Effects (Element4)

10. Procedure 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.
11. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer ‘1A’ deluge sprinkler piping will be reconfigured to allow drainage.

Detection of Aging Effects (Element4) and Acceptance Criteria (Element 6)

12. Procedures 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. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. 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. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2012, an Engineering walkdown of the fire protection piping header along the north wall of the Unit 2 Turbine Building revealed a potential leak location on the supply line to a hose rack. The flanged connection and straight pipe were removed and replaced.
2. In January 2012, a section of 2-inch fire protection “drop” piping in the Turbine Building developed a leak. The investigation for extent of condition and determination for the extent of fire protection piping to be inspected and replaced, as necessary, involved inspections of three locations in the Turbine Building and three locations in the Auxiliary Building. Microbiologically induced corrosion (MIC) was evident in many locations, but the extent of corrosion was not as severe in the Auxiliary Building as it was in the Turbine Building. Despite the less severe corrosion in the Auxiliary Building, the three segments of piping that were inspected were replaced. Similarly, one of the three segments of piping in the Turbine Building was replaced.

   A capital project was proposed for a multi-year process of replacing segments of 2-inch, 4-inch, and 10-inch piping in the Turbine Building. The initial phase that was completed included replacing 200 feet of ten inch piping in the Turbine Building. Additional phases were proposed, and described in the Fire Protection Strategic Plan. See April 2013 and November 2015 operating experience.
3. In June 2012, during inspection of Auxiliary Building fire protection piping minor sediment was discovered in the supply header to the Unit 1 cable tunnel sprinklers. Debris and MIC nodules were discovered inside a spool piece and accessible four inch piping. The sediment and debris were removed, the visual inspection was performed, and the blind flanges and spool pieces were replaced. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

4. In March 2013, NRC Information Notice 13-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction", identified industry operating experience involving the loss of function of fire protection water systems due to the potential for adverse air and water interactions in pre-action and dry-pipe systems. Engineering evaluated the potential for similar adverse conditions and associated degradation in deluge systems at Surry Power Station that are periodically flow tested. Subsequently, in January 2018, a walkdown was performed to confirm that plant design specifications on drainage features for piping downstream of all in-scope pre-action and deluge valves in the fire protection system continued to be in effect. Two locations, one relating to main transformer 1A and one relating to Unit 1 generator hydrogen seal oil system, were identified as having a potential for adverse air and water interactions and entered into the corrective action program.
5. In April 2013, a section of two 10-inch fire protection system piping in the Turbine Building developed a leak. A walkdown of six locations was performed to determine extent of condition in the Turbine Building and the Auxiliary Building. MIC was evident in four locations, but the extent of corrosion in the Auxiliary Building was not as severe. Replacement of 4-inch and 10-inch fire protection header is a like-for-like replacement. The replacement of the Turbine Fire Protection Header was split into four different phases. One phase was to be accomplished each year. The second phase is planned to replace approximately 400 feet of ten-inch header pipe and 200 feet of two-inch hose station pipe. The necessary pipe replacement is included in the Fire Protection Strategic Plan.
6. In February 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1A to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Similarly, volumetric examinations found additional thinning for the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the Unit 2 renewed operating license. Monitoring of the tank floor will continue until the tank floor is repaired or replaced. The necessary tank repair or replacement is included in the Fire Protection Strategic Plan.
7. In August 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1B to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Volumetric examinations found some thinning of the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the Unit 2 renewed operating license. Monitoring of the tank floor will continue until the tank floor is repaired or replaced.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe was cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75% ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In November 2015, an effectiveness review of the Fire Protection Program aging management activity (AMA) (UFSAR Section 18.2.7) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. A comprehensive fire water system assessment recommended a large scale piping replacement of turbine building and auxiliary building piping. The large scale piping replacement project to be performed over multiple refueling outages was identified as a measure to address degradation in carbon steel system piping and to ensure that system intended functions were maintained. Completed and closed phases of this effort have included replacement of approximately 400 feet of 4 inch piping and 200 feet of 2 inch piping in 2014 and approximately 567 feet of 4 inch piping and 303 feet of 2 inch piping in 2015. An additional phase replacing approximately 175 feet of 4 inch piping and 100 feet of 2 inch piping has been completed and is awaiting final testing. Work documents for additional phases are planned and issued for work extending into 2019.

10. In April 2016, results from fire protection system flow tests with the motor driven fire pump in April 2016, July 2013, and April 2010 consistently showed that the system pressure is higher than the required value for the corresponding flow rate. In 2016, the result indicated that the measured pressure exceeded the required pressure by fourteen psi. In 2013, the measured pressure was thirteen psi higher than required. The result in 2010 measured a pressure that was 19 psi higher than required. The trend from these results does not indicate significant degradation over the six-year interval, particularly considering the two most recent measurements. There is confidence that continued implementation of flow monitoring for the fire protection system using the three year interval required by the Technical Requirements Manual will effectively manage aging prior to a loss of intended function.

11. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
12. In November 2017, as part of oversight reviews of the Fire Protection Program AMA (UFSAR Section 18.2.7), an inconsistency was identified in the performance interval for system integrity demonstration by main drain testing. The test interval had been extended from quarterly to each 18 months but the extended interval had not been incorporated into program documents. An Engineering Assignment to review operating experience to trended performance data to 2011 has been completed with no significant degrading trends observed. The new interval is consistent with the test interval of NFPA 25 (2011 Edition) Table 13.1.1.2 modified by NUREG-2191, Section XI.M27, Table XI.M27-1, Note 10.
13. In January 2018 an aging management program effectiveness review was performed for the Fire Protection Program AMA (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

    The Fire Protection Program AMA is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the Fire Protection Program AMA that were reviewed include the inspection of components, the evaluation of inspection results, repairs/replacements, corrective actions, and AMA document updates. Engineering reports from 2006 to 2017 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of fire protection components within the scope of license renewal.

    In the past, multiple fire water piping leaks had been identified in the Unit 1 and Unit 2 Turbine Buildings. As a result, a five phase large scale fire protection piping replacement project has been underway since 2015 to replace Turbine Building header piping and hose station piping as well as the Unit 1 and Unit 2 Auxiliary Building Hose station piping. Two of the Turbine Building phases are complete and two are waiting on testing. Phase five includes the remaining scope in the turbine building and the entire scope in the Auxiliary Building and is planned to start in 2018. Once complete, a large majority of the above ground fire protection piping in the plant will have been replaced, including areas where reoccurring leaks were previously identified.

The fire water/domestic water storage tanks are managed by the Tank Inspection Activities AMA (UFSAR Section 18.1.3); but, are also discussed here for overall fire protection performance considerations. The fire water/domestic water storage tanks were found to have failing internal coatings and loss of material on the tank floors. Estimates for projected useable tank lifetime and evaluations for additional monitoring were performed. Recommendations are being prepared for repair or replacement project considerations.

Multiple operating issues, and obsolescence of the diesel driven fire pump resulted in a design change that replaced the diesel driven fire pump and associated control panel. The new diesel driven fire pump has exhibited substantially improved performance compared to the original fire pump.

Activities to implement NFPA 25, 1998 Edition, Section 2-3.1.1 (1998 edition), testing of sprinklers that have been in service for fifty years have been initiated to prove continued functionality. The Unit 1 and Unit 2 turbine building sprinklers have been sampled and will be tested by 2021, when fifty years of service is reached.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to microbiological induced corrosion, has occurred on several occasions. Periodic fire protection system piping flushes, flow testing and piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. Periodic visual inspections and tank bottom thickness measurements are performed on the fire water storage tanks. In addition to recent piping replacements in the Turbine Building and the Auxiliary Building to address instances of RIC due to microbiologically-influenced corrosion, 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. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. Thinned areas found during the LFET scan are 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 visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

The above examples of operating experience provides objective evidence that the *Fire Water System* program includes activities to perform periodic fire main and hydrant inspections and flushing, sprinkler inspections, functional test, and flow tests to identify loss of material, flow blockage, and loss of coating integrity for in-scope water-based fire protection 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. 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. There is reasonable assurance that the continued implementation of the *Fire 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 *Fire 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.

B2.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), emergency condensate storage tanks (ECSTs), and the emergency condensate makeup tanks (ECMTs). This program also manages aging of the fire protection/domestic water storage tanks (FWSTs) bottom surfaces exposed to soil.

The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. The RWSTs are insulated and rest on a concrete foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs. The insulation of the RWSTs is corrugated aluminum with overlapped seams. The ECSTs and ECMTs are internally coated and protected by concrete missile barriers. Weep holes, located around the circumference of the ECSTs where the concrete missile shield meets the concrete foundation, allow drainage of leakage or condensation to the outside perimeter of the ECSTs. The weep holes will be inspected for water leakage once each refueling cycle. The CATs are skirt supported and insulated with sprayed-on rigid polyurethane foam.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Surface exams of external tank surfaces are conducted to detect cracking on the stainless steel tanks. Inspections of RWST caulking are supplemented by physical manipulation. Thickness measurements of the tanks bottoms are conducted to ensure that design thickness and corrosion allowance criteria are met. A periodic sampling-based inspection is used on the external surfaces of insulated tanks. 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. If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending); however:

- For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.
- For other sampling based inspections 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 at the other unit.

The additional inspections will be completed within the interval (i.e., 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.

If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the internally coated surfaces of the ECSTs and ECMTs. Internal surfaces of the RWSTs and CATs are managed by the *One-Time Inspection* program (B2.1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs and ECMTs are managed by the *Structures Monitoring* program (B2.1.34).

NUREG-2191 Consistency

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks.

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. NUREG-2191 specifies for outdoor tanks, that sealant or caulking is applied at the interface between the tank external surface and concrete or earthen surface to mitigate corrosion of the tank by minimizing the amount of water and moisture penetrating the interface. The ECSTs and ECMTs do not use caulking or sealant at the concrete-component interface and therefore, do not require inspection of the caulking or sealant. The RWST has sealant installed at the interface between the insulation jacketing and the tank concrete foundation.

Justification for Exception:

The ECSTs and ECMTs are insulated from the outside atmosphere by two inches of expansion joint filler foam and surrounded by a two foot thick layer of concrete that provides missile protection. The missile shield and expansion joint filler foam configuration mitigates corrosion of the tank by minimizing water and moisture from penetrating inaccessible exterior tank surfaces. Weep holes are located around the circumference of the ECSTs where the concrete missile shield meets the concrete foundation. The weep holes allow drainage of leakage or condensation to the outside perimeter of the ECSTs and will be inspected for water leakage once each refueling cycle.

The roofs and sides of the RWSTs are insulated and jacketed to mitigate corrosion of the tank by minimizing the amount of water and moisture on the exterior surfaces. As an additional preventive measure, sealant is used at the interface between the insulation jacketing and the tank concrete foundation. The RWST insulation jacketing is installed with overlapping seams to provide a protective outer layer and to prevent water intrusion. The sealant at the interface between the insulation jacketing and the RWST tank concrete foundation provides a boundary to mitigate corrosion of the tank bottom surface and the concrete foundation. In addition, the RWST bottom surface is protected by an oil sand cushion and caulk at the interface between the tank external surface and the concrete surface. Periodic inspections normally performed on the caulk at the tank and concrete foundation will be performed on the insulation caulking and concrete foundation interface. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWST external insulation is removed and sampled for external surface visual examinations.

Detection of Aging Effects (Element 4)

2. NUREG-2191 recommends both visual and volumetric inspection techniques to identify degradation on carbon steel tank external surfaces located outdoors on soil or concrete. The external surfaces of the ECSTs and the ECMTs are encased in a two foot thick reinforced concrete missile barrier with expansion joint filler foam between the external tanks walls and the concrete missile barrier. The concrete missile shields do not allow visual and volumetric examinations of their external surfaces.

Justification for Exception:

The concrete missile shielding and the expansion joint filler foam of the ECSTs and ECMTs act as multiple barriers protecting the external tank surfaces. Weep holes located around the circumference of the ECSTs, where the concrete missile shield meets the concrete foundation, allow for drainage of leakage or condensation to the outside perimeter of the ECSTs. The weep holes will be inspected for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed. Accessible external metallic tank surfaces visible from inside the ECST and ECMT piping penetration house will be inspected once each refueling cycle as an indication of external ECST and ECMT surface condition.

The program inspects the external bottom surfaces of the ECSTs and ECMTs that are exposed to a soil or concrete environment by performing volumetric examination thickness measurements.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. Procedures will be revised to require periodic visual inspections of the refueling water storage tanks (RWSTs) be performed at each outage to confirm that the insulation caulking/sealant at the RWST concrete foundation is intact. The visual inspections of caulking/sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the caulking/sealant will be repaired or replaced and follow-up examination of the tank's surfaces conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWST external insulation is removed and sampled for external surface visual examinations.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs and CATs be performed to identify any loss of material or cracking. A minimum of either 25, one square foot sections or 20% of the surface area of insulation will be required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation.
3. Procedures will be revised to require ECST weep holes be inspected for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed. Accessible external metallic tank surfaces visible from inside the ECST piping penetration house will also require inspection once each refueling cycle as an indication of external ECST surface condition. Volumetric examination thickness measurements of the bottom of both ECMTs (100% of the surface exposed to soil) and both emergency condensate storage tanks will be performed and will occur during each 10-year period starting ten years before the subsequent period of extended operation. Results will be forwarded to engineering

for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of both FWSTs and both RWSTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

5. For the carbon steel tanks (FWST, ECST, ECMT), procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, and surface conditions. The revised procedure will require the inspector confirm adequate lighting is available 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 is recommended. For distant surface inspections, viewing aids such as binoculars may be used. For internal inspections, accessible surfaces will be inspected. Cleaning will be performed as necessary to allow for a meaningful examination. If protective coatings are present, the condition of the coating will be noted.

Corrective Action (Element 7)

6. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191.

   If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending).

   a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.

   b. For other sampling based inspections 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 at the other unit.

The additional inspections will be completed within the interval (i.e., 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.

If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2008, the interior surface of the Unit 1 ECST was inspected in the filled condition. The inspections included ultrasonic thickness (UT) measurements of the tank floor as part of the initial inspection for the first license renewal period. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floor. Based on the observed erosion rate, the remaining service life of the tank bottom is more than twenty years. Internal Inspection of the Unit 1 ECST to assess the extent of corrosion or coating damage is scheduled to be performed in 2022.

2. In December 2008, the interior surface of the Unit 2 ECST was inspected in the filled condition. The inspections included ultrasonic testing (UT) measurements of the tank floor as part of the initial inspection for the first license renewal period. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floors. Based on the observed erosion rate, the remaining service life of the tank bottom is more than twenty years.

3. During the Spring 2014, Unit 2 Refueling Outage, the interior surface of the Unit 2 RWST was inspected in the filled condition. The inspections included UT measurements of the tank floor. The inspections showed only minor corrosion in the stainless steel bottom plate. Based on only minor corrosion being found, the tank is scheduled for a twenty year inspection interval. Inspection results and calculations of the long term corrosion rate based on industry standard API-653 determined the remaining life of the RWST is 335 years. There were no corrective actions required.

4. In August 2014, the interior surface of the Unit 1 ECMT was inspected in the filled condition. The inspection was performed using divers and video equipment. The inspection observed only minor rusting, 1% or less, in localized areas. Interior piping and penetrations were observed to be in good condition. The internal coating was in good condition with the coating being 99.9% intact.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In May 2017, an internal inspection of the Unit 2 ECST was performed. Small blistering and pinhole damage was identified in areas of the coating along the tank walls. Internal coating repairs have been scheduled in work management.

7. In November 2017, as part of oversight review activities, the Tank Inspection Activities (UFSAR Section 18.1.3) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management activity effectiveness review was performed of the Tank Inspection Activities (UFSAR Section 18.1.3). Information from the summary of that effectiveness review is provided below:

   The Tank Inspection Activities is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the Tank Inspection Activities that were reviewed include completed carbon steel tank inspections, including some performed prior to the development of the Tank Inspection Activities. A review was also performed of the Corrective Action Program from 2006 through 2017 for age-related degradation of tanks within the scope of license renewal.

The ECSTs were repaired and re-coated in 1988 to preclude further corrosion. Unit 1 internal inspection results in 1992 and 1997 indicated that the emergency condensate storage tank was in excellent condition. Unit 2 inspection results during 1993, 1996, and 2000 found excellent interior tank conditions. Additional inspections of the ECSTs for both units in December 2008 again confirmed the excellent condition of the tanks. The Unit 2 tank was inspected in May 2017. The inspection found minor blistering and pinholes in the internal coating. Internal coating repairs have been scheduled in work management. There were no new aging management concerns identified.

The fire protection/domestic water storage tanks ‘1A’ and ‘1B’ were inspected in December 2008. Visual inspections of the inside surface confirmed that the tanks have some corrosion. The bottom coatings were blistered but intact. The tanks were inspected in 2014 and the most significant degradation was noted on the tank floor. The results of the visual inspection were that coating degradation was continuing, and that some bare metal was evident. Volumetric examinations found some thinning of the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the operating licenses. The inside walls of the tanks had some coating failure. The measured values for wall thicknesses provided a projected useable lifetime of between 7.9 and 13.6 years (from December 2008) for the ‘1A’ tank and between 13.8 and 19.1 years for the ‘1B’ tank before the bottom plate would reach the minimum acceptable wall thickness. An engineering evaluation was required to identify additional actions to address the limited lifetime of the tanks. Additional actions include future inspections to identify the corrosion rate of thin wall areas and to either repair the tank bottoms in the near future or replace the tanks.

The following carbon steel tank inspections did not identify age-related degradation:

- April 2004, EDG coolant expansion tank (internal visual inspection)
- September 2005, underground fuel oil storage tanks (internal visual inspection, wall thickness measurement)
- February 2007, above-ground fuel oil storage tanks (external visual inspection, wall thickness measurement)
- June 2009, AAC diesel generator air receiver (wall thickness measurement)
- February 2007, AAC diesel generator fuel oil tank (external visual inspection, wall thickness measurement)
- April 2007, security diesel generator fuel oil storage tank (helium leak test)
- February 2007, diesel-driven fire pump fuel oil tank (exterior visual inspection, wall thickness measurement)
- February 2007, emergency service water pump diesel fuel oil storage tank (exterior visual inspection, wall thickness measurement)

The successful inspection of the Unit 2 RWST and Unit 1 CAT at North Anna Power Station in 2010 found no indications of age-related degradation. That result is also applicable to SPS since the RWSTs and CATs at SPS and North Anna Power Station are both made of stainless steel and the tanks have similar installation and operating environments. Surry Power Station allows the inspections of stainless steel tanks to be extrapolated to other tanks that are fabricated from a similar material, installation, and operating environment combination.

In November 2013, based on IE Notice 2013-18 (IEN 13-18), “Refueling Water Storage Tank Degradation,” that was issued to inform licensees of potential issues associated with leakage due to flaws in RWSTs, SPS issued an OE document addressing RWST degradation. No previous RWST leakage was identified. In 2014, an inspection of the Unit 2 RWST identified only minor corrosion issues.

Based on industry operating experience, fleet programs were developed for inspection of underground piping and tank integrity and condition assessment of internally coated/lined tanks, components, and pipes subject to immersion service. The Tank Inspection Activities (UFSAR Section 18.1.3) incorporated applicable buried components and coated components aging management techniques from the fleet programs.

The above examples of operating experience provides objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program includes activities to perform visual inspections of tank internal bare metal surfaces, surface examination of external tank surfaces, and thickness measurements 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 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 *Outdoor and Large Atmospheric Metallic Storage Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* 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.

B2.1.18 Fuel Oil Chemistry

Program Description

The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that manages loss of material from 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:

- Underground Fuel Oil Storage Tanks
- AAC Diesel Generator Fuel Oil Tank
- Emergency Service Water Pump Fuel Oil Tank
- Emergency Diesel Generator (EDG) Auxiliary Fuel Oil Tanks
- Diesel Fire Pump Fuel Oil Tank
- Security Diesel Generator Fuel Oil Tank
- EDG Fuel Oil Base Tanks

The fuel oil storage tanks within the scope of subsequent license renewal do not have internal coatings or linings, with the exception of the security diesel generator fuel oil tank, which is provided with a solvent-based rust preventive film (not considered a coating). 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, the Technical Requirements Manual, 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 fuel oil using the guidelines of the following ASTM standards, as well as additional ASTM standards:

- ASTM D 975-74, “Standard Specification for Diesel Fuel Oils”
- ASTM D 4057-95, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products”
- ASTM D 6217-98, “Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration”
- ASTM D 1796-83, “Standard Test Method for Water and Sediment in Fuel Oil by the Centrifuge Method”

Fuel oil tanks are periodically drained of water and accumulated sediment, cleaned, and internally inspected when accessible. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks are performed in lieu of cleaning and internal inspection. Tanks that cannot be cleaned and internally inspected, and are physically inaccessible for bottom thickness measurements, are monitored for leakage consistent with the current licensing basis. Corrective actions require water to be removed from fuel oil storage tanks when detected and the condition entered in the Corrective Action Program. Additionally, when biological activity is confirmed, or there is evidence of internal tank corrosion, Chemistry evaluates the need to add a biocide to the fuel oil.

The *One-Time Inspection* program (B2.1.20) will be used to verify the effectiveness of the *Fuel Oil Chemistry* program.

NUREG-2191 Consistency

The *Fuel Oil Chemistry* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M30, Fuel Oil Chemistry.

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Tending (Element 5) and Acceptance Criteria (Element 6)

1. NUREG-2191 refers to various cleaning and inspection activities associated with fuel oil storage tanks within the scope of subsequent license renewal. The security diesel generator fuel oil tank and the EDG fuel oil base tanks cannot be cleaned internally and are not accessible for internal inspection or bottom thickness measurements. The basis for exceptions to these requirements is provided below.

<u>Justification for Exception</u>

The security diesel generator fuel oil tank is a heavy gauge steel, 300 gallon, double walled base tank with a leak detection monitor in the annulus between the two tanks. Interior walls of the tank are provided with a solvent-based rust preventive film (not considered a coating). The tank is mounted directly below the security diesel. Internal cleaning and inspection, as well as bottom thickness measurements, are not physically possible due to the design and location of the tank. In lieu of these requirements, the integrity of the inner tank will be monitored by the leak detection instrumentation, which actuates an alarm locally in the Central Alarm Station (CAS) Diesel Generator Room. At least once daily, Operators enter each CAS Diesel Generator Room for visual inspections and to record the level reading in the security diesel generator fuel oil tank. Station Logs require operators to check for leakage from components in the room.

The EDG fuel oil base tanks are fabricated from carbon steel. These 550 gallon tanks are located directly beneath each EDG and cannot be fully and generally accessed for cleaning, internal inspections, or tank bottom thickness measurements. Each base tank is provided with level instrumentation, which actuates an alarm in the Control Room on decreasing level. At least twice daily, operators enter each EDG Room to record EDG fuel oil base tank levels and perform visual inspections. Station Logs require operators check for leakage from components in the EDG Rooms, including the EDG fuel oil base tanks. Prior to the subsequent period of extended operation, a one-time inspection will be performed on the accessible internal surfaces on one EDG fuel oil base tank at SPS. Inspection will be limited due to the restricted accessibility through the tank sampling port. A visual inspection will be performed using a boroscope or equivalent instrument which will provide an acceptable level of information regarding tank degradation on the accessible internal surfaces.

Enhancements

Prior to entering the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be revised to include the emergency diesel generator (EDG) fuel oil base tanks within the scope of the *Fuel Oil Chemistry* program.

Parameters Monitored/Inspected (Element 3)

2. Existing procedures will be revised to include a requirement for quarterly sampling of the EDG auxiliary fuel oil tanks and EDG fuel oil base tanks for particulates and water.

Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), and Acceptance Criteria (Element 6)

3. Procedures will be revised to require the following fuel oil storage tanks within the scope of subsequent license renewal be drained, cleaned, and the internal surfaces visually inspected for degradation within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation:

    - Underground fuel oil storage tanks
    - AAC diesel generator fuel oil tank

    If degradation is found during the internal visual inspection, bottom thickness measurements will be performed. Visual and volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute.

4. Procedures will be developed to perform periodic bottom thickness measurements of the following tanks within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation:

   - EDG auxiliary fuel oil tanks
   - Diesel fire pump fuel oil tank
   - Emergency service water pump fuel oil tank

   Volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute.

5. Procedures will be developed to require an engineering evaluation be performed to document, evaluate, and trend visual and volumetric (as applicable) inspection results for the following fuel oil storage tanks:

   - Underground fuel oil storage tanks
   - AAC diesel generator fuel oil tank
   - EDG auxiliary fuel oil tanks
   - Diesel fire pump fuel oil tank
   - Emergency service water pump fuel oil tank

   The procedures will require unacceptable inspection results, as determined in the engineering evaluation, be documented in the Corrective Action Program. Bottom thickness measurements will be required to be evaluated against the design thickness and corrosion allowance. The frequency between future inspections will not be allowed to be reduced if bottom thickness measurements indicate the corrosion allowance will be exceeded prior to the next scheduled inspection.

   If a tank does not have a stated corrosion allowance, the tank will be evaluated for acceptability in the engineering evaluation. The engineering evaluation will evaluate the need to reduce the time period between future inspections based on inspection results.

Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)

6. Prior to the subsequent period of extended operation, a one-time inspection will be performed on the accessible internal surfaces on one EDG fuel oil base tank at SPS. Inspection will be limited due to the restricted accessibility through the tank sampling port. A visual inspection will be performed using a boroscope or equivalent instrument which will provide an acceptable level of information regarding tank degradation on the accessible internal surfaces.

Corrective Action (Element 7)

7. Procedures will be revised to require a biocide be added when biological activity is detected or if there is evidence of tank internal corrosion.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2005, the underground fuel oil storage tanks were drained, internal surfaces cleaned, and wall thickness measurements performed by certified American Petroleum Institute inspectors. The tanks were found to be in excellent condition with no detectable loss of material.
2. Between 2007 and 2011, API-653, “Tank Inspection, Repair, Alteration, and Reconstruction,” in-service inspections were performed on the following fuel oil storage tanks, consistent with commitments made for initial license renewal:
   - AAC diesel generator fuel oil tank
   - Emergency service water pump fuel oil tank
   - Emergency diesel generator (EDG) auxiliary fuel oil tanks
   - Diesel fire pump fuel oil tank

   The inspections included recording of tank wall thicknesses as well as external visual inspections of fuel oil tanks within the scope of initial license renewal. Each tank was found to be in acceptable condition with inspection results documented in an engineering evaluation.
3. In 2010, during quarterly sampling of the diesel fire pump fuel oil tank, approximately 0.25 inches of water was detected in the tank and was subsequently removed from the tank. A follow-up engineering walkdown revealed the tank flame arrestor rain cover was damaged and was the apparent cause for water entering the tank. The flame arrestor was replaced approximately two weeks later. The next quarterly sample did not identify the presence of water in the tank.
4. In 2013, quarterly sampling identified the presence of sediment in the diesel fire pump fuel oil tank when the sampling device contacted the wall of the tank during routine sampling. It was believed that the cause of the condition may have been the result of water entering the tank through the damaged flame arrestor cover in 2010. A work order was initiated to clean the tank internal surfaces. After cleaning, rust scale on the internal surfaces of the tank remained. The internal corrosion prompted replacement of the tank in 2014.
5. In 2013, routine sampling identified 0.25 inches of water in a underground fuel oil storage tank. A second sample confirmed the presence of water. Additional analysis was performed to confirm the absence of bacteria. The subsequent routine sample of the underground fuel oil storage tank did not identify the presence of water in the tank.

6. In 2015, wall thickness measurements were performed on two fuel oil lines. Both lines exhibited approximately two mils of wastage. The wall thickness as measured was well above the minimum acceptable wall thickness and evaluated as satisfactory by Engineering.

7. In 2015, during routine quarterly sampling, particulates were identified in one of the two underground fuel oil storage tanks that exceeded the acceptance criteria. A follow-up sample showed tank particulate values were acceptable, but still elevated. Work orders were initiated to recirculate and filter both underground tanks. Particulate levels were restored to values well below the acceptance criteria. Post filtration samples taken over a two day period showed particulates levels had increased by approximately two mg/L. Additional samples were performed and sent to two off-site laboratories for independent analysis and verification. The particulate values reported from one off-site lab were approximately three mg/L higher than the second off-site lab. Chemistry personnel verified both labs were conducting the tests to the correct ASTM standard (i.e., ASTM D6217-98). The only difference noted was the two off-site labs used filters from different manufacturers. Both filters provided acceptable results, but one filter indicated particulates of two to three mg/L higher than the second filter.

8. In December 2015, an effectiveness review of the Fuel Oil Chemistry Activity (UFSAR Section 18.2.8) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

9. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

10. In January 2018, an AMP effectiveness review was performed of the Fuel Oil Chemistry Activity (UFSAR Section 18.2.8). Information from the summary of that effectiveness review is provided below:

    The Fuel Oil Chemistry Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the that were reviewed include the scope of the diesel fuel oil tanks managed by the activity, the consistency of sample analyses and techniques with established industry guidance, and a review of pertinent issues found in the Corrective Action Program from 2006 to 2017 for age-related degradation of components exposed to the fuel oil environment.

    The aspects of the AMA reviewed include station procedures and their relationship to industry guidelines which include the EPRI Report No. 1015061, “Guide for the Storage and Handling of Fuel Oil for Standby Diesel Generator Systems”. The AMA is managed in accordance with industry best practices and results do not reveal any loss of intended function as a result of aging. Pertinent issues found in the Corrective Action Program from 2006 through 2017 related to diesel fuel oil were reviewed and determined to be satisfactorily resolved without any further issues.

    The Fuel Oil Chemistry Activity ensures that stored diesel fuel oil is within specifications required for proper operation of the station’s safety-related diesel engines, in order to prevent unanticipated equipment failure due to fuel oil-related issues. Departures from fuel oil specifications for particulates and water have been infrequent and quickly returned to within limits. For example, in 2015, routine sampling of the Emergency Diesel Generator (EDG) Fuel Oil Storage Tanks (FOSTs) identified rising particulate levels in both EDG FOSTs. Backup samples confirmed elevated particulate levels in the fuel oil. Both tanks were recirculated and filtered to reduce particulate levels to acceptable levels within two days. Additional samples were drawn and sent to an offsite laboratory to confirm the return of diesel fuel oil to specifications.

The above examples of operating experience provides objective evidence that the *Fuel Oil Chemistry* program includes activities to perform control of chemistry parameters in to manage loss of material and to perform visual inspection of tanks, and thickness measurements of tank bottoms 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, 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.

B2.1.19 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 beltline materials, in accordance with the version of ASTM E-185 available and used during fabrication of the reactor vessels. 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 the 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 Company prior to 10CFR50 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. For the first element, related to the design of the program, WCAP-7723, “Virginia Electric and Power Co. Surry Unit No. 1 Reactor Vessel Radiation Surveillance Program” and WCAP-8085, “Virginia Electric and Power Co. Surry Unit No. 2 Reactor Vessel Radiation Surveillance Program” for Units 1 and 2, documented the program. The *Reactor Vessel Material Surveillance* program for Unit 1 meets either ASTM E 185-66 or ASTM E 185-70. WCAP-8085 states that the Unit 2 *Reactor Vessel Material Surveillance* program meets ASTM E-185-70. Initially, the requirements relating to the testing method was not mandated by the NRC through a particular version of ASTM E185. Therefore, when a capsule was removed from the reactor vessel, it was customary at the time to document which version of ASTM E185 was used for testing. Overtime, the NRC began the process of approving various editions of ASTM E185 for testing. To date, for testing and schedule considerations, the NRC has approved three editions of ASTM E185-73, -79, and -82. Currently, the *Reactor Vessel Material Surveillance* program complies with ASTM E-185-82 for testing and scheduling.

Since the withdrawal schedule in Table 1 of ASTM E 185-82 is based on plant operation during the original 40-year initial license term, standby capsules have been incorporated to 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 the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criteria has not been tested previously, then 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 reactor vessel, and is provided as input to the neutron embrittlement time-limited aging analyses (TLAAs) described in Section 4.2.

In accordance with 10 CFR Part 50, Appendix H, all surveillance capsules, including those previously removed from the reactor vessel, must meet the test procedures and reporting requirements of ASTM E 185-82, to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including the conversion of standby capsules in 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 (NRC) for approval prior to implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future re-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.

Originally there were eight reactor vessel (RV) capsules installed in each RV prior to plant start-up. Eight capsules is more than the minimum recommended by either ASTM E 185-66 or ASTM E 185-70 for Unit 1 and ASTM E185-70 for Unit 2. Capsule W1 was installed into Unit 2 in 1991 as part of the Master Integrated Reactor Vessel Material Surveillance program. Capsule W1 contained specimens for both Units 1 and 2. Capsule W1 was removed and tested in 1997. The capsules contain representative RV material specimens, neutron dosimeters, and thermal monitors. Withdrawn capsules from each RV have been tested; one of the remaining untested capsules in each RV will be tested during the initial period of extended operation, one of the remaining untested capsules in each RV will be tested during the subsequent period of extended operation, and the remaining untested capsules (including standby capsules) in each RV are available to satisfy potential fluence monitoring requirements during the 20-year subsequent period of extended operation.

Surveillance Capsule Withdraw Schedule for Unit 1

Four Unit 1 capsules have been withdrawn from the RV (T, W, V and X). Three capsules have been tested (T, V and X). Only dosimetry was measured for Capsule W. For the initial period of extended operation, Unit 1 has one untested capsule (Capsule Z), which at its scheduled withdrawal date will be irradiated close to the projected peak neutron fluence of 6.35 x 10^{19} n/cm^2 (E>1.0 MeV), based upon 68 EFPY at the end of the 80-year subsequent period of extended operation. Capsule Z is currently scheduled to be pulled in the 60-year initial period of extended operation during the 2025 Unit 1 refueling outage. As currently scheduled, Capsule Z is estimated to be irradiated to 6.31 x 10^{19} n/cm^2 (E>1.0 MeV), which would not exceed one times the projected peak neutron fluence at the end of the 80-year subsequent period of extended operation. A capsule withdrawal schedule change has been submitted to the NRC to move withdrawal of Capsule Z further out into the initial period of extended operation. Moving withdrawal will ensure that Capsule Z will have been exposed to a fluence between one and two times the projected peak vessel neutron fluence at the end of the 80-year subsequent period of extended operation. The schedule change, if approved, will move the capsule pull to 2027 when the capsule neutron fluence is projected to be 6.41 x 10^{19} n/cm^2 (E>1.0 MeV), which is greater than the projected peak RV neutron fluence for 80 years. Testing of Capsule Z in 2027 will satisfy the initial license renewal schedule for Unit 1.

Untested capsules (including standby capsules) remaining in the Unit 1 RV will be available to satisfy potential fluence monitoring requirements during the 80-year subsequent period of extended operation. Unit 1 will have three untested capsules (Capsules S, U, and Y) irradiated in excess of the 80-year projected peak neutron fluence of 6.35 x 10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation.

The following irradiation values are estimated at the end of the initial period of extended operation (48 EFPY):

- Capsule S is estimated to be irradiated to 5.42 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule U is estimated to be irradiated to 4.59 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule Y is estimated to be irradiated to 6.24 x 10^{19} n/cm^2 (E>1.0 MeV)

An 80-year projected peak neutron fluence irradiation of 6.35 x 10^{19} n/cm^2(E>1.0 MeV) is estimated to be attained by standby Capsules S, U, and Y in 2040, 2047, and 2032, respectively, during the subsequent period of extended operation. Withdrawal and testing of Capsule Y from Unit 1 will satisfy the expectation to test one capsule during the subsequent period of extended operation.

Two standby capsules will remain in the reactor, one of which will satisfy the requirement for fluence monitoring specified in ASTM E-185 and required by 10 CFR 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements.”

Surveillance Capsule Withdraw Schedule for Unit 2

Six of the Unit 2 capsules have been withdrawn from the Unit 2 RV (X, W, W-1, S, V and Y). Four capsules have been tested (X, W-1, V and Y). Only dosimetry was measured for Capsule W and Capsule S. Unit 2 has one untested capsule (Capsule U) which will be irradiated in excess of the projected peak neutron fluence of 7.26 x 10^{19} n/cm^2 (E>1.0 MeV) that is based upon 68 EFPY at the end of the subsequent period of extended operation. Capsule U is scheduled to be pulled in the initial license renewal period in 2027 during the Unit 2 refueling outage. As currently scheduled, Capsule U is estimated to be irradiated to 5.95 x 10^{19} n/cm^2 (E>1.0 MeV) by 2027, which would not exceed one times the projected peak neutron fluence at the end of the 80-year subsequent period of extended operation. A capsule withdrawal schedule change has been submitted to move the Capsule U withdrawal further out into the initial period of extended operation, to ensure that it will have been exposed to a fluence between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. The schedule change, if approved, will move the capsule pull to 2032 when the capsule projected neutron fluence will be 7.31×10^{19} n/cm^2 (E>1.0 MeV) which is greater than the projected peak RV neutron fluence for 80 years. Testing of Capsule U in 2032 will satisfy the initial license renewal schedule for Unit 2.

Untested capsules (including standby capsules) remaining in the Unit 2 RV will be available to satisfy potential fluence monitoring requirements during the 80-year subsequent period of extended operation. Unit 2 will have two untested capsules Capsules (T and Z) that will be irradiated in excess of the 80-year projected peak neutron fluence of 7.26×10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation.

The following irradiation values are estimated at the end of the initial license renewal period (48 EFPY):

- Capsule T is estimated to be irradiated to 6.65×10^{19} n/cm^2 (E>1.0 MeV)
- Capsule Z is estimated to be irradiated to 5.39×10^{19} n/cm^2 (E>1.0 MeV),

An 80-year projected peak neutron fluence irradiation of 7.26×10^{19} n/cm^2(E>1.0 MeV) is estimated to be attained by standby specimen Capsules T and Z in 2036 and 2046, respectively, during the subsequent period of extended operation. Withdrawal and testing of Capsule T from Unit 2 will satisfy the expectation to test one capsule during the subsequent period of extended period of operation.

One standby capsule will remain in the reactor to satisfy the requirement for fluence monitoring specified in ASTM E-185 and required by 10 CFR 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements.”

Request for NRC Approval of Changes to the Surveillance Capsule Withdraw Schedule

10 CFR 50, Appendix H, requires that prior to withdrawal of Capsule S or U from Unit 1 RV or Capsule Z from Unit 2 RV, a proposed withdrawal schedule with a technical justification will be submitted to the NRC for approval. By way of this SLR application, Dominion is requesting that NRC review and approve the changes to the proposed withdrawal schedule shown in the following:

- Table B2.1.19-1, Surveillance Capsule Withdraw Schedule For Surry Unit 1, and
- Table B2.1.19-2, Surveillance Capsule Withdraw Schedule For Surry Unit 2.

As part of Operating Experience, consistent with statements in Regulatory Guide 1.99, Revision 2, Dominion considers the use of surveillance data from other sources when they become available. As such, information from surveillance capsules withdrawn from sister plant vessels is used to supplement information from the *Reactor Vessel Material Surveillance* program subject to the credibility limitations stated in Regulatory Position 2.1 and 2.2 of Regulatory Guide 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 reactor vessel components and reactor vessel internal components.

NUREG-2191 Consistency

The Reactor Vessel Material Surveillance program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M31, Reactor Vessel Material Surveillance.

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 the Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)

1. The RV Material Surveillance program for Unit 1 will be amended for Capsule Y to be pulled during the subsequent period of extended operation. Capsule Y will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.
2. The RV Material Surveillance program for Unit 2 will be amended for Capsule T to be pulled during the subsequent period of extended operation. Capsule T will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Dominion is a member of the Babcock and Wilcox Owner's Group Reactor Vessel Working Group (RVWG). While not required, SPS participates in the RVWG's Master Integrated Reactor Vessel Surveillance Program (MIRVSP). The MIRVSP integrates the plant specific reactor vessel surveillance programs of the participants, the existing supplemental B&W Owners Group irradiation capsules, and additional supplemental irradiation capsules to assure the availability of high fluence and thermal annealing data for the participants' reactor vessels. One objective of the MIRVSP is to maximize the effectiveness of data sharing among participants to assure that required data is available to the participants for current and extended plant operation.
2. In 1997, Unit 1 Capsule X Withdrawal and Test: Per BAW-2324, “Analysis of Capsule X, Virginia Power Surry Unit No. 1,” the specimens in Unit 1 Capsule X were exposed to fluences equivalent to approximately 16.1 EFPY, 2.11 x 10^{19} n/cm^2 based on the calculated fluence, and satisfy the upper-shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. The adjusted reference temperatures have been shown to be less than those used in the Unit 1 P-T limit curves, thereby demonstrating margin in the operating limits.
3. In 2002, Unit 2 Capsule Y Withdrawal and Test: Per WCAP-16001, “Analysis of Capsule Y from Dominion Surry Unit 2 Reactor Vessel Radiation Surveillance Program, the specimens in Unit 2 Capsule Y were exposed to fluences equivalent to approximately 20.3 EFPY, 2.72 x 10^{19} n/cm^2 based on the calculated fluence, and satisfy the upper-shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. The adjusted reference temperatures have been shown to be less than those used in the Unit 2 P-T limit curves, thereby demonstrating margin in the operating limits.
4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

Procedure changes were completed as necessary to ensure the above items were satisfied.

5. In November 2017, as part of oversight review activities, the Reactor Vessel Integrity Management Activity (UFSAR Section 18.2.14) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

6. In January 2018, an aging management program effectiveness review was performed of the Reactor Vessel Integrity Management Activity (UFSAR Section 18.2.14). Information from the summary of that effectiveness review is provided below:

   The Reactor Vessel Integrity Management Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the Reactor Vessel Integrity Management Activity that were reviewed included aging management activity procedures, documents, and incorporation of industry operating experience.

   The AMA procedure and associated documents were examined to evaluate the effectiveness of the Reactor Vessel Integrity Management Activity with respect to aging management. The procedure defines activities required to ensure adequate fracture toughness of the reactor vessel beltline plate and weld material consistent with the following parameters: heatup and cooldown limits, PTS reference temperature, a bounding fast fluence value, and upper shelf energy. These parameters are documented in the SPS UFSAR and Technical Specifications and as such changes to these parameters require NRC review.

   As a result of the revised projected fluence calculations performed for the RV nozzles a revision to the reactor vessel material surveillance capsule withdraw schedule was submitted to the NRC for approval by Dominion Energy Virginia Letter 17-243 (July 2017) to reflect the latest projected fluence calculations in the estimated capsule fluence values. The proposed changes provide asset optimization and ensure the revised estimated standby capsule fluence values coincide with the nearest respective unit refueling outage for withdrawal.

   A review of industry operating experience resulted in a program procedure revision to include Westinghouse Technical Bulletin TB-16-5 that ensures proper installation and seating of surveillance capsules.

   The Reactor Vessel Integrity Management Activity ensures that the Dominion reactor vessels are consistent with the applicable regulations and industry standards with respect to reactor vessel embrittlement concerns.

The above examples of operating experience provides objective evidence that the *Reactor Vessel Material Surveillance* program includes activities to perform withdrawal and testing of reactor vessel capsule specimens to manage a reduction in fracture toughness due to irradiation of the ferritic reactor vessel 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. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements are 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 Vessel Material Surveillance* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

1. The continued implementation of the *Reactor Vessel Material Surveillance* 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.

Table B2.1.19-1 Surveillance Capsule Withdraw Schedule[a] For Surry Unit 1

Capsule Identification	Capsule Location	Estimated Withdrawal EFPY/Year	Insert EFPY/Year	Estimated Capsule Fluence (x 10^{19})[b]
T[c]	285°	1.1/1974	NA	0.271
W[c]	55°	3.4/1978	NA	0.368
V[c]	165°	8.0/1986	NA	1.80
X	65°	13.5/1994	NA	1.72
X	165°	NA	13.5/1994	NA
X[c]	165°	16.1/1997	NA	2.11
Z	245°	13.5/1994	NA	1.72
Z	285°	NA	13.5/1994	NA
Z[c]	285°	44.0/2027	NA	6.41
U	45°	13.5/1994	NA	0.893
U	65°	NA	13.5/1994	NA
U[e]	65°	NA	NA	4.59 (48.0 EFPY)
				6.82 (68.0 EFPY)
S[e]	295°	NA	NA	5.42 (48.0 EFPY)
				7.65 (68.0 EFPY)
Y	305°	15.8/1997	NA	1.52
Y	165°	NA	15.8/1997	NA
Y[d]	165°	60/2044	NA	6.24 (48.0 EFPY)
				8.14 (60.0 EFPY)

a. Withdrawal schedule meets requirements of ASTM E 185-82, *Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels,* dated July 1, 1982.

b. 48.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 60-year license period. 68.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 80-year license period. Fluence values for withdrawn capsules are obtained from capsule test reports.

c. These capsules are required to satisfy the requirements of ASTM E 185-82 during the initial period of extended operation.

d. This capsule will be removed during the subsequent period of extended operation.

e. Standby Capsules S and U are available to satisfy potential fluence monitoring requirements during the subsequent license renewal period. Future projected capsule fluence values are related to asset management objectives.

Table B2.1.19-2 Surveillance Capsule Withdraw Schedule[a] For Surry Unit 2

Capsule Identification	Capsule Location	Estimated Withdrawal EFPY/Year	Insert EFPY/Year	Estimated Capsule Fluence (x 10^{19})[b]
X[c]	285°	1.2/1975	NA	0.297
W[c]	245°	3.8/1979	NA	0.636
V[c]	165°	8.4/1986	NA	1.89
Y	295°	13.9/1995	NA	1.83
Y	165°	NA	13.9/1995	NA
Y[c]	165°	20.3/2002	NA	2.72
U	65°	27.1/2009	NA	3.16
U	285°	NA	27.1/2009	NA
U[c]	285°	49.0/2032	NA	7.31
T	55°	20.3/2002	NA	1.72
T	165°	NA	20.3/2002	NA
T[d]	165°	63.0/2047	NA	9.66
Z	305°	13.9/1994	NA	1.28
Z	245°	NA	13.9/1994	NA
Z[e]	245°	NA	NA	5.39 (48.0 EFPY)
				8.21 (68.0 EFPY)
S	45°	15.0/1996	NA	1.07
W1	285°	NA	10.9/1991	NA
W1[f]	285°	16.2/1997	NA	0.78

a. Withdrawal schedule meets requirements of ASTM E 185-82, *Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels,* dated July 1, 1982.

b. 48.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 60-year license period. 68.0 EFPY corresponds to the estimated cumulative core burnup at the end of the 80-year license period. Fluence values for withdrawn capsules are obtained from capsule test reports with updates to the final values based upon WCAP-18242-NP.

c. These capsules are required to satisfy the requirements of ASTM E 185-82 during the initial period of extended operation.

d. This capsule will be removed during the subsequent license renewal period.

e. Standby Capsules Z is available to satisfy the potential fluence monitoring requirements during the 20-year license renewal and subsequent license renewal periods. Future projected capsule fluence values are related to asset management objectives.

f. Master Integrated Reactor Vessel Materials Surveillance Program capsule.

B2.1.20 One-Time Inspection

Program Description

The *One-Time Inspection* program is a new condition monitoring program that will manage loss of material, cracking, and reduction of heat transfer of components containing reactor coolant, treated borated water, secondary water, fuel oil, or lubricating oil 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 to be developed.

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. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.

Where an aging effect identified during an inspection does not meet acceptance criteria or projected results of the inspections of a material, environment, and aging effect combination do not meet the above acceptance criteria, a periodic inspection program is developed for the specific material, environment, and aging effect combination. The periodic inspection program is implemented at all of the units on site with same combination(s) of material, environment, and aging effect.

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 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.

Consistent with further evaluation 3.1.2.2.2(2) the *One-Time Inspection* program (B2.1.20) will perform a magnetic particle test inspection of susceptible locations of the continuous circumferential transition cone closure weld on each steam generator (minimum 25% examination coverage of each weld) prior to the subsequent period of extended operation.

The *One-Time Inspection* program will be implemented, and inspections will begin ten years before the subsequent period of extended operation. Inspections will be completed at least six 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.

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 examples of operating experience provide objective evidence that the *One-Time Inspection* program will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2012, minor pitting was observed in the lower quadrant of a carbon steel pipe in the condensate system on either side of the section that was removed to correct an abnormal alignment. The other attributes were considered acceptable. An engineering evaluation determined that the minor pitting did not indicate significant degradation of the piping that would present an integrity concern for license renewal. No further action was recommended.
2. In May 2015, a visual inspection was performed on the internal surfaces of the feedwater system to fulfill a license renewal commitment regarding the work control process. A feedwater system valve was removed to allow inspection of the valve internal surfaces and adjacent tubing. No age-related degradation was noted.

The above examples of operating experience provide objective evidence that the *One-Time Inspection* program will include activities to perform visual inspections to identify loss of material, cracking and reduction of heat transfer for components containing reactor coolant, treated borated water, secondary water, fuel oil, or lubricating oil 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 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 *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 or greater than 8% aluminum).

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 ten components per population at each unit will be visually and mechanically (gray cast iron and ductile iron components) inspected. If the inspection conducted for ductile iron in the 10-year period prior to a 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 at each unit, two destructive examinations will be performed for that population. In addition, for sample populations with less than 35 susceptible components at each unit, 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 maybe reduced by two for each component that is destructively examined for each sample population.

For two unit sites the periodic visual and mechanical inspections can be reduced from ten to eight because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the James River. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

External surfaces of buried components that are coated consistent with the *Buried and Underground Piping and Tanks* program (B2.1.27) are excluded from the sample population.

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.

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:

- 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, and
- 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In Spring 1988, inspection of butterfly valves located in the main condenser inlet and outlet piping and in the service water piping associated with the component cooling heat exchangers identified degradation due to graphitic corrosion. IE Notice 84-71 (IEN 84-71) “Graphitic Corrosion of Cast Iron in Salt Water,” informed licenses of a potentially significant corrosion problem in salt or brackish water environments. Unit 1 and Unit 2 are located on the salinity line of the James River. This water falls within the brackish category. Both units were designed with a number of cast iron components in the circulating water and service water systems. In response to IEN 84-71, a graphitic corrosion evaluation was performed. The evaluation resulted in the examination of a large sample of components, valves, strainers, and pumps which revealed various degrees of graphitic corrosion. Wall thickness measurements were obtained by ultrasonic testing and verified by mechanical measurements. Destructive measurements were made on some valves. The conclusion of the evaluation was that various valves in the circulating water and service water system would be replaced. The originally installed butterfly valves were uncoated gray cast iron. Due to the brackish water environment, these valves had reduced wall thickness due to graphitic corrosion. In order to ensure seismic qualification, the valves were replaced with valves manufactured from ductile iron due to its mechanical properties. In order to provide extended service life, the wetted portion of the ductile iron (valve disc and body inside surface) had a liquid epoxy coating applied.
2. In January 1996, a materials analysis was performed of the inlet end and approximately five inches of a vacuum priming seal recirculating pump heat exchanger. The inlet end of the heat exchanger was degraded as a result of flow accelerated corrosion. Cross sections taken at the tube to tubesheet interface also revealed signs of dealloying of the copper-zinc tubesheet on the service water side. A definite decrease in the percentages of zinc was detected in these areas. The tubes appeared to be a copper-nickel alloy with a small amount of iron and manganese present. The six originally installed heat exchanger assemblies with copper-nickel alloy tubes and copper-zinc tubesheets were replaced with heat exchanger assemblies with 316 stainless steel tubes and 316L stainless steel tubesheets. To minimize tube fouling, corrosion damage and tube leaks experienced by service water, the heat exchangers were removed from the turbine building service water subsystem by a design change in 1997 and are now cooled by bearing cooling water.

3. In October 2006, circulating water system inlet motor operated valve (MOV) butterfly valves were inspected and found to have numerous coating failures and valve body corrosion degradation. The valves were made from cast A536 ductile iron. The corrosion damage was described as galvanic and graphitic corrosion due to coating failure. A design modification replaced the circulating water Inlet MOV valves with new valves manufactured from a material not susceptible to selective leaching, passivated 316L stainless steel and no problems have been identified since replacement.
4. In 2010, graphitic corrosion was evident when two bearing cooling heat exchanger service water valves, gray cast iron, ASTM A 126, were found to have metal loss after about fifteen years of in service operation. Neither valve had through-wall leakage. The replacement valves are manufactured of ASTM A-536 ductile iron and were coated prior to installation. Replacement work orders were established to replace the valves every fifteen years. The component cooling heat exchanger service water inlet valves are also coated ductile iron valves that were replaced during the fall 2013 Unit 1 refueling outage. The old valves were observed to have limited coating degradation and no noticeable metal loss. Based on engineering observations, ductile iron has exhibited a better performance in service water applications.

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 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 *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 a new condition monitoring program that will manage 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 will utilize volumetric or destructive examinations to augment the visual examinations (VT-1) required by ASME Code, Section XI.

The *ASME Code Class 1 Small-Bore Piping* program will focus on socket and butt welds for piping that is susceptible to stress corrosion cracking (SCC), and cracking due to thermal or vibratory fatigue loading. One-time inspections will determine the presence of cracking for locations within the scope of the *ASME Code Class 1 Small-Bore Piping* program. With the exception of socket welds for the seal injection line attachments to the reactor coolant pump (RCP) thermal barrier casings at the seal injection nozzles, there is no operating experience of age-related cracking. Therefore, except for those seal injection socket welds, inspection samples will be selected consistent with NUREG-2191 Section XI.M35, Table XI.M35-1, Category A. One-time inspections will be performed in the six-year period prior to the subsequent period of extended operation. The one-time inspection samples will consist of 3% of the total population in each unit (up to ten maximum) for susceptible butt welds and susceptible socket welds. Each socket weld subject to destructive examination can be credited twice toward the total number of examinations. For Unit 1, eight of the 250 socket welds, and ten of the 360 butt welds, will be examined. For Unit 2, ten of the 647 socket welds, and eight of the 267 butt welds will be examined. Evaluations of inspection results will determine the need for scope expansion or periodic monitoring of small-bore piping.

The small-bore socket welds for the seal injection lines will be treated as a unique subset within the small-bore socket weld population in accordance with NUREG-2191, Section XI.M35, Table XI.M35-1, Category B, due to a prior crack on a Unit 1 RCP seal injection line in 1998. The crack was most likely due to a postulated pre-existing defect at the toe of the weld, and vibratory fatigue due to the loosening of a piping support that was subsequently tightened. Category B requires a one-time inspection in the six year period prior to the subsequent period of extended operation for 10% of the total population in each unit. The implementation will involve liquid penetrant (LP) examinations for the three reactor coolant loops for both units.

NUREG-2191 Consistency

The ASME Code Class 1 Small-Bore Piping program is a new program that, when implemented, will be consistent, with exception, to NUREG-2191, Section XI.M35, ASME Code Class 1 Small-Bore Piping.

Exception Summary

The following program element(s) are affected:

Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. NUREG-2191 indicates, “cracking is detected through either destructive or non-destructive examinations of piping welds and base metal materials. The volume of these materials is examined to detect flaws or other discontinuities that may indicate the presence of cracks.” As an exception, in lieu of a volumetric examination for the seal injection line to the reactor coolant pump (RCP) thermal barrier casing at the seal injection auxiliary nozzle (three welds per unit), LP examinations will be performed.

Justification for Exception

The RCP seal injection line has a pipe stub directly connected 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. This injection pipe stub connects to the thermal barrier casing with a socket weld. There are only three of these socket welds per unit, and since the weld connects the piping to a limited-accessibility, thick flange-like component, these welds constitute a unique subset within the small-bore socket weld population.

As a result of the exceedingly limited space in the area of the seal injection line weld to the thermal barrier casing, a meaningful volumetric examination is not feasible. A limited volumetric examination could only be performed if the reactor coolant pump assembly is disassembled for maintenance, which could provide for an opportunistic volumetric examination in accordance with the applicable maintenance procedures. In lieu of a volumetric examination, an LP examination will be performed, assuming sufficient accessibility, which will provide an acceptable level of information regarding the integrity of the weld. An LP examination for the seal injection line weld on one of the three coolant loops will be performed prior to the subsequent period of extended operation. Examinations for the seal injection line weld on the two remaining loops will be performed, one per ISI interval, during the subsequent period of extended operation.

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Code Class 1 Small-Bore Piping* program will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 1998, Operations personnel, upon observing an increase in reactor coolant system leakage, entered Containment and identified a leak in the area of the seal injection line to Unit 1 ‘C’ loop reactor coolant pump (RCP) at the seal injection weld to a thermal barrier casing flange. The leak was found to be a weld crack, and was determined to be a through-wall, non-isolable RCS leak covered by the Technical Specifications. The weld failure was postulated to be the result of a pre-existing indication at the toe of the weld, perhaps from a lack of fusion coupled with vibrational stress from high-cycle fatigue due to a loose rod hanger immediately upstream. A component failure analysis could not be performed because a section of the weld defect could not be obtained. The cracked weld was excavated and a new line was welded in place utilizing enhanced design features in accordance with approved procedures. The loose pipe support for the RCP seal injection line was corrected. Corresponding welds for the A-loop and B-loop RCP seal injection lines were non-destructively tested (dye penetrant) with no indications noted. The associated pipe supports for the ‘A’ and ‘B’ loops were inspected to ensure proper installation. No deficiencies were identified.

2. In April 2015, after reviewing a Root Cause Evaluation from North Anna Power Station regarding leakage from a reactor coolant system loop drain line, SPS committed to inspect the two inch hot and cold leg drain lines on the three reactor coolant system loops, using EPRI MRP-146, “Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines”. The volumetric inspections of the drain lines identified three crack-like indications in the ‘B’ loop cold leg drain. The three indications were axial in orientation, in the base metal, and located in the horizontal section of piping between the first elbow and the downstream valve. There was no evidence of any leakage at the three locations in the ‘B’ loop cold leg drain. The section of piping with the indications was removed for destructive examination, and was replaced satisfactorily. Volumetric examinations were performed on the other two cold leg drain lines and on the three hot leg drain lines. No indications were identified.

   The results of the destructive examination for the cold leg drain pipe concluded that the crack-like indications were defects associated with tearing or deformation of the inner surface that occurred during fabrication. The cracks were not induced by thermal fatigue.

The above examples of operating experience provide objective evidence that the *ASME Code Class 1 Small-Bore Piping* program will include activities to perform volumetric and visual inspections to manage cracking of ASME Code 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 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 *ASME Code Class 1 Small-Bore Piping* program will effectively manage aging prior to a loss of intended function.

Conclusion

The implementation of the *ASME Code Class 1 Small-Bore Piping* 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.

B2.1.23 External Surfaces Monitoring of Mechanical Components

Program Description

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages 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; loss of preload of HVAC closure bolting; and 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, general, pitting, and crevice corrosion; surface imperfections such as cracking and wastage; coating degradation such as cracking, flaking, or blistering; evidence of insulation damage or wetting; leakage; 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 will be 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) are 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 are 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 stainless steel and aluminum components exposed to aqueous solutions or air environments containing halides. A minimum sample of 25 inspections will be performed from each of the aluminum and stainless steel component populations every ten years.

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 ten years during the subsequent period of extended operation. Following insulation removal, ASME Code, Section XI VT-1 examinations or surface examinations will be conducted to detect loss of material and cracking of the component surfaces. A minimum of twenty-five one foot axial length piping sections and components for each material type will be inspected.

If any sampling-based inspections to detect cracking in aluminum and stainless steel 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 at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., 10 year inspection interval) in which the original inspection was conducted.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, severity of operating conditions, and lowest design margin.

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 will follow site procedures consistent with the ASME Code. Non-ASME Code inspection procedures will 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 (B2.1.27). 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).

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 enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. The Engineering walkdown procedure will be revised to include an item in the walkdown checklist to inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture.

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

2. The Engineering walkdown procedure will be revised to add the following requirements:

   a. Metallic Components

      - No surface imperfections, loss of wall thickness, flaking, or oxide coated surfaces
      - No blistering of protective coating
      - No evidence of leakage (for detection of cracks) on the surfaces of stainless steel and aluminum components
      - No accumulation of debris on air-side heat exchanger surfaces

   b. Elastomers and Flexible Polymers

      - No exposure of reinforcing fibers, mesh or underlying metal (for elastomers or flexible polymers with internal reinforcement)
      - No blistering, loss of thickness, dimensional change, or scuffing
      - No hardening of elastomeric elements as evidenced by a loss of suppleness during tactile inspection

   c. Insulation Metallic Jacketing

      - Inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture.

   d. HVAC Closure Bolting

      - Check that a sample of closure bolting that is in reach is not loose

Detection of Aging Effects (Element 4)

3. The Engineering walkdown procedure 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, the enhancement will also specify that such surfaces will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

Detection of Aging Effects (Element 4)

4. The Engineering walkdown procedure will be revised to provide non-ASME Code inspection guidance related to lighting, distance and offset for walkdown 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.
5. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. A minimum of 25 inspections for cracking will be performed from each of the stainless steel and aluminum component populations assigned to the program every ten years. For insulated components exposed to condensation, a minimum of 25 one foot axial length sections and components for each material and environment combination will be inspected for loss of material and cracking after the insulation is removed. 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.
6. The Engineering walkdown procedure will be revised to specify that visual inspection of elastomers and flexible polymers will be supplemented by tactile inspection to detect hardening. Visual inspections will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area.

Monitoring and Trending (Element 5)

7. A new procedure will be developed to evaluate and project the rate of any 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)

8. A new procedure will be developed 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.

Corrective Actions (Element 7)

9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections to detect cracking in aluminum and stainless steel 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 at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., 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 *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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2009, Engineering noted a section of a condenser waterbox outlet rubber expansion joint was blistered and was soft to the touch. Photos were taken of the condition, and a condition report written. Engineering evaluated the condition against the criteria in a station inspection procedure. The evaluator noted that there was no liquid behind the soft areas, no cracking, and no delamination. The evaluator noted that the procedure indicated that soft spongy area on the internal circumference of a joint could be due to uncured arch material. Therefore, using the guidance in the procedure, the condition was determined to be acceptable.
2. In May 2013, during a system walkdown outdoors, vegetation was noted growing in the insulation of three lines associated with the fire protection system. The insulation was removed, and no damage to the piping from the vegetation was noted, however, some rusting was noted on the surface of the piping. The damaged insulation was repaired to prevent any further water intrusion.

3. In September 2013, corrosion was noted on the bottom of a section of Unit 1 emergency service water pump discharge piping. The external pipe coating was bulging, indicating corrosion beneath. Additionally, a piece of the coating was missing. Engineering performed non-destructive examination (NDE) on the area of localized coating degradation. The pipe wall thickness results were compared against the minimum wall thickness and found to be acceptable. Based on engineering evaluation, no further degradation was expected following recoating of the pipe.

4. In March 2014, an inspection of ductwork upstream of a cable spreading room air handler was performed. The inspection identified an area of corrosion in the top of a duct elbow and a condition report was submitted. A follow-on inspection with the insulation removed documented substantial rust damage on multiple sections of the ducting and another condition report was written. The unit was subsequently replaced as part of a design change to rectify persistent ventilation degradation and equipment obsolescence issues. The design change replaced the major mechanical components of the Unit 1 and Unit 2 cable spreading room ventilation systems and repaired associated ductwork. The design change also included replacement of the insulation and covering of the ductwork with an aluminum jacket for enhanced protection from water intrusion. Aluminum jacket is installed in a manner so as to shed water consistent with plant specifications.

5. In December 2015, an effectiveness review of the General Condition Monitoring Activities (UFSAR Section 18.2.9) was performed. This aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. System engineer walkdowns were identified as not being consistently maintained in the designated plant database and the walkdown attributes associated with license renewal activities were not being documented. The issues were documented in the Corrective Action Program. Corrective actions included:

    - Development and implementation of work group specific training for engineering roles and responsibilities related to walkdowns.
    - Implementation of changes to the walkdown procedure
    - Implementation of a process for ensuring system walkdown records are maintained
    - Development of a template in the walkdown tracking database to match the specific requirements in the walkdown procedure

    A follow-up review was performed in February 2016, when 22 of the 24 corrective actions had been completed. The review indicated that walkdowns were being performed and documented in accordance with license renewal requirements. The remaining corrective actions were completed subsequent to the follow-up review.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the General Condition Monitoring Activities (UFSAR Section 18.2.9) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed of the General Condition Monitoring Activities (UFSAR Section 18.2.9). Information from the summary of that effectiveness review is provided below:

    The General Condition Monitoring Activities are meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the General Condition Monitoring Activities that were reviewed include system engineer walkdowns to identify age-related degradation of plant equipment within the scope of license renewal. Walkdown records from 2006 through 2017 were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions were taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 identified during walkdowns.

    In 2015, several issues with Engineering walkdowns were identified, including that the walkdowns were not being documented and maintained in the tracking database as required. This operating experience is discussed in item number five above.

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 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; loss of preload of HVAC closure bolting; and reduced thermal insulation resistance 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, 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.

B2.1.24 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 (RCS) pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel (RV) where flow-induced fretting causes wear at discontinuities in the path from the RV instrument nozzle to the fuel assembly instrument guide tube. Such discontinuities could be present in the areas of the lower core plate, the core support forging, and the RV penetration nozzle. The flux thimble tube design is a double-walled, asymmetrical configuration to accommodate thermocouple leads located in the annulus between the inner and outer flux thimble tubes. The outer tube is the component that is most susceptible to wear due to its contact with the discontinuities. The inner tube through which the incore detector travels is the reactor coolant system pressure boundary. The double wall design significantly reduces the potential for wear of the inner tube pressure boundary. Operating experience confirms the absence of failure for the inner tube pressure boundary. Periodic eddy current examinations are performed every other operational cycle as an augmented inspection that is described in the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) to confirm the integrity of the inner flux thimble tube, and are consistent with the recommendations of NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors”.

NUREG-2191 Consistency

The *Flux Thimble Tube Inspection* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M37, Flux Thimble Tube Inspection.

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):

Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)

1. An inspection procedure will be developed specifically for flux thimble tube eddy-current inspections, rather than continuing to use a generic procedure for tubing inspection. The procedure will include the acceptance criterion, with the basis, for loss of material for the inner flux thimble tube, and identify remediating actions to be implemented if the acceptance criterion is exceeded.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Flux Thimble Tube Inspection* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In July 1991, results of eddy current testing (ECT) for the inner flux thimble tubes were obtained for Units 1 and 2, and were provided to the NRC as responses to NRC Bulletin 88-09. For both units, there was no indication of age-related degradation of the pressure boundary provided by the inner flux thimble tube.
2. Beginning in 2001, a project was initiated to replace the flux thimble tubes in small groups during a series of refueling outages. The high-pressure fittings on the flux thimble tube connections at the seal table had become worn and needed to be replaced. When the fitting was replaced, the associated flux thimble tube also was replaced. That effort was completed in 2015.
3. In October 2016, while retracting Unit 1 flux thimble B-7, a through-wall pinhole leak was noted about four inches below the high pressure fitting. The observed hole was on the outer flux thimble tube; the inner flux thimble tube is the primary pressure boundary. An inspection in 2006 noted that the flux thimble tube B-7 outer wall was inadvertently damaged by plant personnel. Satisfactory eddy current results were obtained. Since the inner flux thimble tube was not affected, flux thimble tube B-7 remained fully functional for flux mapping.
4. In January 2018, an aging management program effectiveness review was performed of the Augmented Inspection Activities (UFSAR Section 18.2.1) that contains reactor vessel incore detector thimble tubes among its inspection activities. The summary of the effectiveness review for the Augmented Inspection Activities is provided in the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1).

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 that 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 systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Flux Thimble Tube Inspection* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Flux Thimble Tube Inspection* 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.

B2.1.25 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 loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) 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.

ASME Code, Section XI visual (VT-1) examinations or surface examinations will be conducted to detect cracking of stainless steel and aluminum 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. Physical manipulation or pressurization will be used to augment the visual examinations conducted under this program in order to detect hardening or loss of strength.

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 nineteen components per population at each unit will be inspected.

Where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections to nineteen components per population at each unit. The reduced total number of inspections is acceptable because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the James River. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

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 at both Unit 1 and Unit 2. 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.

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 are 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, 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.

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 enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require inspection of metallic components for flaking or oxide-coated surfaces.
2. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following:
   a. Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., “ballooning” and “necking”)
   b. Loss of wall thickness
   c. Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers
3. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area.

Detection of Aging Effects (Element 4)

4. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 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 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 procedure will require the condition of the coating to be documented.

5. A new procedure will be developed to specify that 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 nineteen components per population at each unit 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.

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

6. A new procedure will be developed to evaluate and project the rate of any 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)

7. A new procedure will be developed 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.

Corrective Actions (Element 7)

8. A new procedure will be developed to specify that 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 at both Unit 1 and Unit 2. 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.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2009, a leak was identified in a raw water vacuum priming elbow servicing a Unit 1 component cooling heat exchanger. The condition was determined to be pitting due to microbiologically induced corrosion (MIC). The pipe section was removed and replaced. A separate condition report written at the same time documented another leak at a different location in the same section of piping. Three separate through wall leaks were noted on this section of piping and documented on the two condition reports. To provide more information as to extent of condition, another section of vacuum priming pipe on a different component cooling heat exchanger was removed, and showed evidence of MIC, although not through wall. Engineering recommended creation of preventive maintenance items to replace the vacuum priming piping with similar configuration to the MIC-damaged sections on the four Unit 1 component cooling heat exchangers every ten years to prevent future through wall leaks. The new preventive maintenance items were approved in October 2010.
2. In March 2012, during performance of a preventive maintenance activity, it was identified that the housing for an air handling unit was degraded. The internal condition of the housing showed corrosion of the metal. The unit was subsequently replaced as part of a design change to rectify persistent ventilation degradation and equipment obsolescence issues. The design change replaced the major mechanical components of the Unit 1 and Unit 2 cable spreading room ventilation systems and repaired associated ductwork.
3. In May 2013, Engineering performed non-destructive examination on a length of Unit 2 recirculation spray heat exchanger service water vent piping. An elbow in the length of piping showed significant wall thinning. This piping is vented to atmosphere, but is temporarily fully wetted with service water when flow testing the recirculation spray heat exchangers. Quarterly ultrasonic testing of the piping was performed to monitor the progression of thinning until the piping was replaced in the next outage. Inspection during the replacement of the piping documented exfoliation due to corrosion. This is an example of recurring internal corrosion in the service water system.

4. In May 2015, discharge piping in the Unit 1 Turbine Building from plumbing system sump pumps was identified to have several leaks at a threaded fitting at a rate of four to five gallons per minute. The fitting material is cast iron exposed to waste water. The sump liquid pH was determined to be neutral, so the cause was attributed to corrosion from stagnant water over time. Other recent examples of leaks in plumbing system piping at fittings have also been noted. Soft patch repairs were made to the leaks, and work orders initiated to replace the piping. This is an example of recurring internal corrosion in the plumbing system.

5. In December 2015, an effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience activity elements. A sample of completed as-found inspection forms was reviewed and identified that the documentation of as-found inspections was inconsistent and needed improvement.

   As a corrective action, training of mechanical maintenance personnel on expectations for properly documenting as-found conditions was conducted. An additional corrective action that recommended enhancement of the as-found inspection form was closed administratively. This operating experience is revisited in the January 2018 AMP effectiveness review. Due to the need for additional improvements noted during the January 2018 AMP effectiveness review, a condition report was entered into the Corrective Action Program.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the Work Control Process Activity (UFSAR Section 18.2.19) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). Information from the summary of that effectiveness review is provided below:

   The Work Control Process Activity plans and conducts testing and maintenance activities, both preventive and corrective. Visual inspections are conducted of the internal surfaces of plant components and adjacent piping that are in the scope of license renewal to monitor for aging effects such as cracking and loss of material. Potential age-related degradation conditions are recorded on “as-found” inspection forms and dispositioned as necessary in the Corrective Action Program. A review was performed of station operating experience identified via the Work Control Process Activity, including conditions identified in the Corrective Action Program from 2006 through 2017.

   While the automatic inclusion of the as-found inspection form in work packages ensures that inspections are performed on in-scope components, a review of a sampling of completed inspection forms throughout the period from 2006 to 2017 showed that inspection personnel are not consistent in the level of detail provided on the form when recording observed conditions. A self-assessment of the License Renewal program documented the issue of inconsistent level of detail on as-found inspection forms in 2015. This operating experience is discussed in item number five above. Corrective actions completed as a result of this Condition Report do not appear to have been effective.

   A sample of as-found inspection forms from March to June 2017 (after the corrective actions were completed) was reviewed and contained the following typical discrepancies:

   - Condition Report numbers not appropriately documented on the inspection sheets concerning discovered aging effects
   - Aging effects not described in detail and documented in the inspection sheet notes section
   - Aging effects table not filled out adequately
   - License Renewal inspection sheets inappropriately dispositioned

   To improve program effectiveness, the following will be addressed and documented during the next aging management program effectiveness review:

   - Investigation and evaluation of inspection results and corrective actions from a sample population of License Renewal equipment work orders
   - Clarification of procedural guidance on inspection parameters including documentation of aging effects
   - Re-training of inspection personnel (current staffing and maintenance of this population of inspectors)
   - Re-training of personnel reviewing inspection forms (current staffing and maintenance of this population of reviewers)

A condition report has been generated in the Corrective Action Program to document and track implementation of these corrective action

<u>Recurring Internal Corrosion</u> (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has been observed in the service water and plumbing systems. Occurrences in the service water system have been noted over a period from 2007 to 2013. Occurrences in the plumbing system have been noted over a period from 2011 to 2018. Corrective actions have been taken previously, and additional actions have been initiated as noted below to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25). Future occurrences of RIC will be documented in accordance with the Corrective Action Program.

Corrective actions include:

- Sections of service water piping not within the scope of GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” that have documented leaks in the past due to corrosion of carbon steel from a raw water environment have been replaced. Opportunistic inspections of susceptible piping and components will be performed when the system boundary is opened. Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined via the Corrective Action Program if significant loss of material is detected.
- Work orders have been created to replace affected portions of the plumbing system piping along an approximately 77 foot length in the Unit 1 Turbine Building basement that have documented leaks from corrosion due to stagnant water in the lines. Opportunistic inspections of susceptible piping and components in other portions of the system within the scope of subsequent license renewal will continue to be performed when the system boundary is opened.

Recurring internal corrosion has also been observed in various lined or coated components, such as the main condenser channel heads and the 96 inch circulating water discharge piping. The aging effects of internally coated/lined surfaces are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28). Specific operating experience examples and corrective actions that discuss such aging effects are documented in the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program.

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 loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also includes activities to perform opportunistic inspections to identify hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric 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 manage 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, 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.

B2.1.26 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 ensures 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) are trended in the program's database, and corrective actions are initiated when the presence of water is identified which could include evaluating for in-leakage and corrosion product buildup.

The *Lubricating Oil Analysis* program applies monitoring methods that are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation.

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 ensure that degradation is not occurring and component intended functions are 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 enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3)

1. Procedures will be revised to incorporate existing guidelines for lube oil and electro-hydraulic control fluids into sampling procedures.

Acceptance Criteria (Element 6)

2. Procedures will be revised to include a statement that phase-separated water in any amount is not acceptable.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In February 2009, during performance of 1-OPT-FW-003 on the Unit 1 turbine driven auxiliary feedwater pump #2, the observed oil sample taken was not clear. The samples were sent to two different labs for analysis. Both labs confirmed that the oil met the specifications and considered the oil to be normal. The analysis indicated no abnormal wear products present, was slightly elevated particulate, but was still acceptable. The only remaining causes for the cloudy oil are degraded additives in the oil or just the age of the oil. Based on the test results conducted by separate labs and available documentation from EPRI, the amount of water needed to cause the oil to be cloudy was not present. Maintenance drained and flushed inboard and outboard bearing housings and then drained, cleaned, and refilled the sump to the proper level. The sample taken from the return to service run following oil replacement showed a less cloudy condition, but was still not clear. The second condition was acceptable and most likely caused by the residual oil remaining in the system when the oil was replaced. Recent oil samples were obtained in 2016, 2017, and 2018. The water content was less than the 0.5% maximum allowable limit from EPRI.
2. In August 2011, high particulate count was observed in the oil for the Unit 1 motor driven auxiliary feedwater pump motor ‘3B’ outboard bearing. The oil analysis for the sample from the bearing was marginal for lubricant condition due to high particulate count. With a new bearing installed and new oil, the likely source of the particle count was residual debris in the reservoir from bearing preparation. The particulate was primarily dirt, dust, fiber, and some cutting wear material. Engineering determined that the bearing would perform its intended function with the particulate in the outboard motor reservoir. In October 2013, old oil was removed from the inboard and outboard bearings. The reservoir was flushed and filled with new oil. Subsequent oil samples were obtained in 2012, 2013, and 2015. Analysis from the lab showed particulate counts were elevated, but wear products or debris were minimal, and in all cases indicated the bearing will perform its intended function including its nine hour mission time.

3. In May 2012, Engineering was assigned an action to determine and initiate actions to enhance the sampling process in response to numerous particulate contaminated oil samples. A search was conducted of the Industry OE database for key words “lube oil sample port.” Numerous results were obtained and reviewed for SPS and other plants in the industry as well. Results tended to be concerned with contaminated oil samples obtained without the use of sample ports and low oil levels from slight leakage. Engineering was tasked with initiating required actions to enhance operations, maintenance, and engineering procedures to ensure sample consistency and cleanliness. In September 2012, an audit of the onsite oil analysis program was performed by a vendor. The vendor stated that consistent, representative samples are the key to a successful oil analysis program. The vendor recommended improvements enhanced the ability to obtain accurate oil samples and eliminate the likelihood of particulate contaminated samples. Recommended improvements were in areas of training, equipment modifications, procedure enhancements and oil issuing. Since the vendor recommended enhancements were incorporated into the program in 2012, the acceptability rate for oil sampling has trended upward from 92.1% to 97.1% over a four year period from 2012 to 2016.
4. In October 2016, samples taken from the Unit 1 feedwater pump ‘1A’ lube oil sump showed evidence of water emulsified with oil and free water at the bottom of the sample. The apparent cause of the water in the lube oil was excessive mechanical seal leakage on the outboard seal combined with a clogged drain line. Maintenance cleaned the inboard and outboard pump bearings, replaced the oil filter, drained, flushed, filled the system, and ensured the sump was wiped clean. In November 2016, the inboard and outboard seals were replaced. A follow-up oil sample tested negative for water following another clean and flush process. Engineering increased the oil sampling frequency to monthly.
5. In December 2016, a review was performed of corrective actions for electro-hydraulic control (EHC) fluid and no adverse age related operating experience was identified over a 10-year period from December 2006 to December 2016.The EHC fluid is replaced at periodic intervals recommended by the original equipment manufacturer/supplier.

The above examples of operating experience provides objective evidence that the *Lubricating Oil Analysis* program includes activities to perform lubricating oil and EHC (electro-hydraulic control) fluid analysis to identify any degradation in the quality of the lubricating oil or hydraulic oil that could cause loss of material, mechanical wear, or loss 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Lubricating Oil Analysis* 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.

B2.1.27 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, blistering, and cracking on external surfaces of piping and tanks in soil or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of steel, stainless steel, copper alloys, fiberglass reinforced plastic, and concrete. Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), 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 electrochemical verification of the effectiveness of cathodic protection, non-destructive evaluation of pipe or tank wall thicknesses, performance monitoring of fire mains, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active CP system. Monthly periodic inspections confirm CP system availability and annual CP surveys are conducted to assess the effectiveness of the CP system. The program uses the -850 mV relative to CSE (copper/copper sulfate reference electrode), instant off criterion specified in NACE SP0169 for acceptance criteria for steel piping and tanks and determination of cathodic protection system effectiveness in performing cathodic protection surveys. The program includes an upper limit of -1200 mV on cathodic protection pipe-to-soil potential measurements of coated pipes to preclude potential damage to coatings. 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 balance of piping and tanks within the scope of subsequent license renewal are not provided with CP. Based on soil sampling and testing, it has been determined that installation and operation of CP is not necessary. Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive 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.”

External inspections of buried components within the scope of subsequent license renewal will occur opportunistically when they are excavated for any reason.

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, the sample size is increased.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (B2.1.16). The water-based fire protection system is normally maintained at required operating pressure and is monitored such that a loss of system pressure is detected and corrective action initiated.

The *Selective Leaching* program (B2.1.21) is applied in addition to this program to manage selective leaching for applicable materials in soil environments.

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 elements:

Preventive Actions (Element 2)

1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings.

Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)

2. Procedures will be revised to include visual inspection requirements and acceptance criteria for:
    a. Absence of cracking in fiberglass reinforced plastic components and evaluation of blisters, gouges, or wear
    b. Minor cracking and loss of material in concrete or cementitious material provided there is no evidence of leakage exposed or rust staining from rebar or reinforcing “hoop” bands

Acceptance Criteria (Element 6)

3. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. Alternatives will be demonstrated to be effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured.

   When using the electrical resistance corrosion rate probes:

   a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar

   b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 1994, leakage was identified in buried, carbon steel, emergency diesel generator (EDG) fuel oil lines. The leak was discovered through external visual inspection, internal boroscope inspection, and pressure drop air testing, and considered to be due to internal pitting corrosion. The 1½ inch schedule 80 carbon steel piping system was replaced with 2½ inch schedule 160 carbon steel lines in 1995. Excavation, fill placement, compaction, and testing of the soil were done in accordance with design specifications. The bedding material for the fuel oil lines is a select granular fill consisting of clean well graded sand. The coating material provided is a synthetic elastomeric tape wrap. A passive cathodic protection system was installed in 1995 to protect the buried fuel oil piping from corrosion. This passive system became degraded as the sacrificial anodes were increasingly being drained off to station grounds.

   In May 2015, an impressed current cathodic protection system was installed and placed in service to replace the passive cathodic protection system on the buried, carbon steel, EDG fuel oil lines. One of the two new rectifier units was in a degraded condition from August 2015 through February 2016, until it was restored to operation by corrective maintenance. The NACE annual inspection completed in April 2016 concluded that the system was providing adequate cathodic protection consistent with NACE criteria. Monthly inspections confirm rectifier operation.

2. In May 2004, portions of the Unit 2 auxiliary feedwater system experienced leakage in the buried carbon steel recirculation piping. The primary cause of the leak was pitting corrosion due to poorly applied coating. As a corrective action, the Unit 1 and Unit 2 AFW recirculation system piping is no longer buried and was rerouted through the safeguards building basement. The extent of condition assessment portion of the root cause evaluation noted the following:
    - The corresponding auxiliary feedwater recirculation line on Unit 1 had been discovered to be leaking and was subsequently bypassed and abandoned as part of a design change,
    - Stainless steel liquid waste piping in excellent condition,
    - Carbon steel chilled water piping with wrap intact and no indication of corrosion,
    - Carbon steel auxiliary feedwater piping with wrap in good condition and no indication of corrosion, and
    - Leaking fuel oil pipe with indications of localized pitting that was replaced and re-routed.
3. In June 2010, while removing coating from the Unit 2 condensate makeup buried carbon steel piping, pitting was identified on several areas of the pipe where the coating had been removed. The pitting was seen at three locations and was characterized as shallow. The as-found condition of the pipe was within code requirements and determined to be fit for service. Following inspection the coating was restored.
4. In July 2012, excavation revealed leakage from a buried Unit 2 ten inch stainless steel condensate supply line. There appeared to be an approximate three to four inch circumferential crack in the line that had started along the outside diameter of the pipe. The crack was determined to be caused by transgranular stress corrosion cracking due to mechanical damage by excavation equipment. The replacement pipe is not buried and has been rerouted through the turbine building.
5. In June 2016, a Dominion Energy fleet self-assessment was performed on the Underground Piping and Tank Integrity (UPTI) Program to ensure the program is supporting the goal of providing long term reliability of buried and underground piping and tanks; to ensure consistency with NEI 09-14, Guideline for the Management of Underground Piping and Tank Integrity, and NSIAC requirements; and ensure the program meets industry best practices. Implementation of the UPTI Program was reviewed to confirm performance of inspections, effectiveness of scheduling and tracking, and program optimization based on inspection results.

This self-assessment identified one performance deficiency in that the 2015 UPTI Life Cycle Management Plan (LCMP) was issued by engineering transmittal without being approved at Plant Health Steering Committee. The 2016 UPTI LCMP was approved by Plant Health Steering Committee.

A strength was noted in that the inspections required by the UPTI LCMP are being scheduled, tracked, and performed as expected; and the results are being used appropriately to determine the next inspection. The UPTI team reviews operating experience during fleet calls and incorporates the experience into the program and inspections as appropriate.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In May 2017, during the as-found coating inspection on Unit 2 buried carbon steel condensate makeup piping, coating was missing on approximately 270 degrees of the pipe circumference from the center of the excavated area into the soil on the east side. Coating on the bottom was remaining. There was no visible leakage from this condensate makeup line piping segment. Ultrasonic testing of the piping segment demonstrated that the minimum wall thickness requirement was met or exceeded at each location tested. The protective coatings were restored.

8. In November 2017, as part of oversight review activities, the Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

9. In January 2018, an aging management program effectiveness review was performed of the initial license renewal Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1). Information from the summary of that effectiveness review is provided below:

   The Buried Piping and Valve Inspection Activities is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the Buried Piping and Valve Inspection Activities that were reviewed included the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports of inspections results from 2004 to 2016 were reviewed to confirm inspections were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of buried components within the scope of license renewal.

A living Life Cycle Management Plan (LCMP) that identifies inspection plans at the next five year interval is maintained based on piping wall thickness calculations, risk ranking and internal/industry operating experience. In 2004, leakage from a buried auxiliary feedwater pipe and in 2012 leakage from a buried condensate pipe resulted in design changes to reroute the piping through non-buried environments. Observed coating degradations during recent inspections resulted in coating repairs and pipe wall thickness evaluations to anticipate rates of change and confirm fitness for service. Quarterly reviews by the fleet UPTI program owners review industry and plant operating experience, including corrective actions, to identify adjustments to the program. Recent fleet operating experience from North Anna Power Station for a service water to auxiliary feedwater pipe resulted in accelerated inspection schedules for similar carbon steel piping at SPS.

In 2014, based on industry feedback, the EDG fuel oil sacrificial anode cathodic protection (CP) system was replaced with an impressed current system. Recent program reviews identified required updates to the maintenance procedures for the impressed CP system. In June 2017, as part of an Industry Material Review Visit, no adverse findings were noted for the UPTI program. Recent industry research and development is reviewed and incorporated into the program as appropriate. New soil survey studies consistent with EPRI 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," will identify any areas of soil corrosivity.

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, cracking, and blistering for buried and underground piping and tanks 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, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Buried and Underground Piping and Tanks* 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.

B2.1.28 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 an existing condition monitoring program that manages loss of coating integrity of the in-scope components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, and waste 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.

Periodic visual inspections are conducted for each coating/lining material and environment combinations of the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s).

For tanks and heat exchangers, the accessible surfaces are inspected. Piping inspections are sample-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, “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 are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. 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 are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

NUREG-2191 Consistency

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4).

1. Every four or six years, NUREG-2191 recommends either an inspection of a representative sample of 73 one foot axial length circumferential segments of piping or 50% of the total length of each coating/lining material and environment combination inspected, whichever is less at each unit. For two-unit sites, 55 one foot axial length sections of piping (nineteen if manufacturer recommendations and industry consensus documents were complied with during installation) are inspected per unit. An exception is taken to the inspection sample size, inspection, and re-inspection frequency.

Justification for Exception

For each unit, existing piping inspections are performed on 25% of the circulating water system (large bore piping) and service water system internal coatings every eighteen months, thereby inspecting 100% of the circulating water system and service water system piping every six years.

The existing coating on circulating water and service water piping approached the end of its expected service life and has been marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system. The coating has experienced localized failures exposing the pipe wall to brackish water resulting in corrosion of the exposed pipe material. The circulating water and service water piping is being repaired using a carbon fiber reinforced polymer (CFRP) lining to restore the piping pressure boundary and provide a corrosion-resistant barrier on piping internal surfaces. The CFRP relining is expected to be complete in future refueling outages.

For piping with CFRP lining, the inspection interval will be extended to twelve years if:

a. Identical coating/lining material is installed with the same installation requirements in redundant trains with the same operating conditions and at least one of the trains is inspected every six years, and

b. The coating/lining is not in a location subject to erosion that could result in damage to the coating/lining.

The determination to extend the inspection interval will be based on operating experience and inspection results.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of the Program (Element 1) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require additional inspections of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection frequencies will be modified, as necessary, to ensure consistency with NUREG-2191:
    - Circulating water system waterbox air separating tanks
    - Condensate polishing outlet piping
    - Vacuum priming tanks
    - Vacuum priming seal water separator tanks
    - Auxiliary steam drain receiver tank
    - Water treatment piping
    - Flash evaporator demineralizer isolation valve
    - Pressurizer relief tanks

Parameters Monitored/Inspected (Element 3)

2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage.
3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program.
4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation.

Detection of Aging Effects (Element 4)

5. Procedures will be revised to require cementitious coatings/linings inspectors to have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience.

Monitoring and Trending (Element 5)

6. Procedures will be revised to require a pre-inspection review of the previous “two” condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities.

Acceptance Criteria (Element 6)

7. Procedures will be revised to require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material.

Corrective Action (Element 7)

8. Procedures will be revised to permit the “removal” of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation.
9. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if:
    a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal
    b. The potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered) adhesion testing (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area
    c. An evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component and
    d. Follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.
10. Procedures will be revised to require additional inspections if one of the license renewal inspections does not meet acceptance criteria due to current or projected degradation.

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 has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2008, the interior surface of the Unit 1 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floor. The inspection of the Unit 1 ECST showed minor blistering and little evidence of corrosion that would impact minimum wall thickness.
2. In December 2008, the interior surface of the Unit 2 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floors. An internal inspection of the Unit 2 ECST was performed in May 2017. Small blistering and pinhole damage was identified in areas of the coating along the tank walls. Internal coating repairs are scheduled in work management.
3. In December 2008, an engineering inspection of the ‘A’ main control room chiller revealed condenser tube erosion, but no leaks were identified and Engineering had no operability concerns. Per Engineering recommendation, Plastocor coating was placed on the tubes of ‘A’ main control room chiller in June 2009, and on the tubes of ‘C’ main control room chiller in July 2010. In January 2010, inspection revealed that the coating on the 'C' main control room chiller condenser outlet tubes had started to degrade. Coating in the tubes started to flake, crack and bubble up. Inspections of the tubes with a borescope revealed that there were spots where the copper oxide layer was flaking off. There was no corrosion, pitting, or cracking in the tubes or tubesheet. Maintenance successfully removed the loose, flaking and cracking coating. Engineering performed Eddy Current Inspection of the condenser tubes and no tube degradation was identified. In June 2010 the condenser outlet tubes were re-coated. Subsequent inspection in January 2011 revealed that the tubes and tubesheet were free of cracking, separation, or delamination. Coating was flaking three to three and half inches inside the tubes. Coating was removed where it was flaking. Inspection in June 2011 revealed no signs of degradation, pitting or erosion. Inspection performed in January 2015 and February 2016 found the condenser tubes to be acceptable for service.

4. During the Fall 2010 refueling outage (RFO), Engineering inspected the outlet line from a Unit 1 recirculation spray cooler. The line was found to have general corrosion occurring beneath the coating at the outlet flange interface on the upper endbell of the heat exchanger. The degraded coating was removed; base metal/weld repairs and coating repairs were performed during the Unit 1 fall RFO. Ultrasonic testing examination on the outlet service water flange was performed in November 2010. Exfoliation had not extended past the raised edge of the slip-on flange. Service water piping wall loss was not evident. Follow-up inspection of the outlet line was performed and coating degradation was found at the outlet flange interface on the upper end bell of the heat exchanger. Coating and weld repair were completed in November 2010. Another follow-up inspection in January 2011 noted areas of coating delamination, including the first four to six inches of pipe downstream from a service water motor operated valve, the area around the tap for a service water flow element and the tap for a service water resistance temperature detector. The areas of pipe where the delamination of coatings occurred were blasted and recoated in January 2011. Inspection of the recirculation spray cooler and ultrasonic testing of the service water vent piping is scheduled in work management.
5. In October 2010, five through wall holes were identified in a piping elbow of the Unit 1 “B” main condenser circulating water discharge piping. The piping contained raw water, and the material of construction was epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in February 2011.Subsequent inspections and repairs were performed in September 2016 with epoxy coating and March 2018 with the installation of the CFRP lining.
6. In November 2010, while removing a Unit 1 service water motor operated valve from the system to replace the an adjacent service water expansion joint, it was noted that the coating on the inner diameter of the pipe flange was not intact and the weld metal in the pipe to flange connection had corroded. The service water was in direct contact with the carbon steel pipe. Base metal/weld repairs and coating repairs were performed in November 2010. The weld repairs were visually inspected for a minimum acceptable wall thickness. The visual inspections were completed satisfactorily.
7. In November 2012, during the weld inspection of a Unit 2 main condenser outlet waterbox, eight areas for repair were identified due to degradation of the epoxy coating, including two through-wall areas. The waterbox contains raw water, and the material of construction is epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in November 2012. This is an example of recurring internal corrosion in the circulating water system. Subsequent inspections and repairs were performed in April 2014, October 2015, and April 2017.

8. In April 2015, circulating and service water Carbon Fiber Reinforced Polymer (CFRP) pipe repair was performed on the interior surface of circulating water and discharge service water piping to repair and strengthen the existing pipe systems. The service water and circulating water systems piping are constructed of carbon steel piping that was originally internally coated with a coal tar epoxy coating. Over the years of operation, the coating has experienced localized failures exposing the pipe wall to brackish water and resulting in corrosion of the exposed pipe material. Since 1990 there has been a long-term service water pipe repair project which replaced the coal tar coating with a coating system using a multi-functional epoxy coating product to improve the corrosion protection. This project was completed in July 1998. The new coating system did improve the corrosion protection; however, it still has a limited service life approximately 15 to 25 years which results in localized coating failures. This coating approached the end of its expected service life and has been only marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system.

   A permanent repair of the service and circulating water systems piping that restores the system pressure boundaries and provides a corrosion resistant barrier to the existing system was applied to sections of the service water and circulating water piping system. This design change addresses service water piping downstream of the component cooling heat exchangers and circulating water piping downstream of the Unit 1 condenser outlet valves. The CFRP system is used to repair any degraded piping sections. The CFRP relining began in 2015 and is expected to be complete in future refueling outages. The repair process used CFRP composite designed to take the place of the existing carbon steel pipe, and as such, becomes a pipe that is capable of meeting the original design requirements of this pipeline formed within the discharge piping. The outlet piping from the component cooling heat exchangers (CCHXs) that has been relined with CFRP is rated for full system pressure, design temperature, transient load, weight effects, and vacuum pressures combined with external ground water static pressure.

   In a relief request dated December 20, 2017 the NRC staff concluded that the proposed CFRP composite system provides reasonable assurance of the buried circulating water and service water piping structural integrity and leak tightness. The NRC staff stated in correspondence to Dominion dated December 20, 2017, “The CFRP repair system alternative will remain in place for the life of the plant.” The station will continue to inspect approximately 25% of the circulating water system (large bore piping) and service water system internal coatings, including repaired sections, every 18 months, thereby inspecting 100% of the circulating water system and service water system piping every six years at each unit. The NRC further concluded, that based on operating experience, there is reasonable assurance to expect the CFRP repaired pipes to perform successfully and the maintenance and inspection programs will confirm acceptable performance during future inspection intervals. CFRP relining is expected to be complete in future refueling outages.

CFRP systems have been utilized in brackish water environments for over 25 years, and it is a common environment for application. This includes exposure to harsh freeze-thaw environments in bridge and pile applications within the transportation industry, upgrade to concrete infrastructure within power generation and industrial facilities, and pipeline repair and upgrade with CFRP - these types of applications are and have been completed in brackish environments with successful performance of the CFRP system.

9. In February 2016, engineering performed a coating/welding inspection inside the Unit 1 ‘B’ component cooling heat exchanger inlet and outlet endbells. The inspection revealed fifteen areas inside the inlet endbell and ten areas on the outlet endbell requiring coating repairs. The outlet endbell also had three areas requiring base/metal weld repairs. There were no through-wall holes discovered. The weld repairs and coating were performed in February 2016. A quality inspector visually inspected the final repaired areas and a magnetic particle examination was performed on the final weld repairs. The work was completed and inspected satisfactorily.

<u>Recurring Internal Corrosion</u> (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has occurred in the coated/lined service water system piping, plumbing system piping, main condenser waterboxes and the 96-inch circulating water discharge piping. Corrective actions such as circulating water and service water liner installation that was started in April 2015 are in progress, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28). Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined by the Corrective Action Program if significant loss of material is detected. Work orders have been created to replace affected portions of the plumbing system piping. Future occurrences of RIC will be documented in accordance with the Corrective Action Program. Corrective actions include:

a. Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with CFRP. The design changes for both units are in progress, and no documented aging effects for CFRP coated sections of the 96-inch circulating water outlet piping have been identified. The CFRP design changes will be completed over the next several refueling outages. Separate design changes will install CFRP in the 96 inch circulating water inlet piping and the 24-, 30-, 36-, 42-, and 48-inch service water piping from the circulating water system to the recirculation spray and supply for the component cooling heat exchangers. For epoxy coated piping sections and main condenser channel heads that do not yet have the CFRP lining installed, inspection is performed of approximately 25% of the circulating water and service water system internal coatings each refueling cycle, thereby 100% of the circulating water and service water piping is inspected every six years. Since the initial installation of the CFRP system in April 2015, there have been no condition reports to date indicating a loss of coating integrity in CFRP lined components. The CFRP system has a 50-year service life.

The component cooling heat exchanger channel heads are epoxy-coated carbon steel exposed to raw water (service water). Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal. Inspection of the component cooling heat exchangers (CCHXs) in January 2011 discovered coating failures. Coating repairs were performed. A multi-functional epoxy coating system was applied to the Unit 1 CCHXs starting Unit 1 RFO 2013.

b. The CFRP lining is designed to meet the existing design requirements for the lines in which it will be installed and will serve as the system pressure boundary. In contrast to the existing carbon steel pipe, CFRP is not susceptible to pitting in a raw water environment. Therefore, augmented inspections will not be necessary on piping lined with CFRP. For piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, inspection of approximately 25% of the circulating water and service water system internal coatings each refueling cycle will be performed. As a result of the inspection protocol with a 25% sample population, 100% of the circulating water and service water internal coatings is inspected every six years.

   Plant operating experience has demonstrated that the yearly inspections of the component cooling heat exchanger channel heads are frequent enough to detect degradation before causing a loss of intended function.

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 includes activities to perform visual inspections of internal surfaces to identify deficient or degraded coatings/linings 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 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 *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* 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.

B2.1.29 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 material, loss of sealing, loss of preload, and loss of leak tightness by providing aging management of the steel liner of the concrete Containment. ASME Code, Section XI, Subsection IWE 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 Containment liner plate and its integral attachments, Containment penetrations, Containment hatches, airlocks, 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. Plant operating experience has not identified any discernible bulges requiring further examination. 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 third quarter of 2017, IWE Containment inservice inspections are performed in accordance with the 2007 Edition of ASME Code, Section XI, Subsection IWE (through the 2008 addenda), supplemented with the applicable requirements of 10 CFR50.55a(b)(2)(ix). Prior to the end of each interval, the IWE Program Plan is revised to reflect the appropriate update of ASME Code, Section XI, consistent with the provisions of 10 CFR 50.55a.

Containment seals and gaskets are included in the scope of the *10 CFR Part 50, Appendix J* program (B2.1.32). Service Level 1 coatings are included in the scope of the *Protective Coating Monitoring and Maintenance* program (B2.1.36).

The design of the Containment liner leak chase system does not include access boxes of the type addressed in NRC Information Notice 2014-07, and the liner-to-concrete interface does not include a moisture barrier. Therefore, the IWE program does not include any moisture barrier component.

Procedures will 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used.

There are no stainless steel penetration bellows installed as part of the Containment pressure boundary. Stainless steel high energy pipes that penetrate the containment are connected to carbon steel penetration sleeves with dissimilar metal welds. Plant operating experience has not identified any stress corrosion cracking associated with these welds. The *ASME Section XI, Subsection IWE* program (B2.1.29) and the *10 CFR Part 50, Appendix J* program (B2.1.32) manage the aging of these dissimilar metal welds. Containment penetrations were not analyzed for cyclic fatigue and will require surface examinations in addition to visual examinations to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading. 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. Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side.

The *ASME Section XI, Subsection IWE* program (B2.1.29) manages aging of the steel liner of the concrete containment building. The *10 CFR Part 50, Appendix J* program (B2.1.32) manages loss of leak tightness, loss of sealing, and leakage through containment. 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-specific operating experience associated with inaccessible areas from the IWE program has not identified any indications of corrosion.

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.

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):

Preventive Actions (Element 2)

1. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants."
2. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used.

Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6)

3. Procedures will be revised to specify surface examination and acceptance criteria, in addition to visual examination, to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis.

Detection of Aging Effects (Element 4)

4. Procedures will be revised to specify a one-time volumetric examination of metal liner surfaces that are inaccessible from one side if triggered by plant-specific operating experience. Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 1998 and 1999, IWE inspection results for Unit 1 and Unit 2, respectively, found no significant degradation down to level of the interface joint with the concrete floor. Several areas of concrete were excavated to check the condition of the steel liner below the interface joint. These excavations confirmed the absence of significant degradation for the liner. Wall thickness measurements showed that considerable margin remains with respect to minimum acceptable values.
2. In 2015, while conducting a detailed visual examination (VT-1) of the concrete-liner interface of the Unit 2 Containment, per the ASME Code, Section XI, Subsection IWE, Table IWE-2500-1, Category E-C, areas with degraded coatings and surface corrosion were identified in the concrete-liner interface along the back of the Containment sump. The VT-1 examination did not reveal any adverse condition other than surface corrosion in the area identified. Corrective action, in accordance with IWE-3122, resulted in cleaning the surface area, performing non-destructive examination (NDE), and recoating the surface. Ultrasonic testing (UT) verified wall thickness integrity. The lowest reading was 0.398 inches, with nominal wall thickness of 0.375 inches.
3. In 2015, follow-up inspection of the coatings repair to the Containment liner to floor interface identified two areas behind the inside recirculation spray pump suction header supports, which required further coatings repair. A work order was issued and the coatings in these two areas were repaired in May 2017.
4. In May 2016, the NRC issued Regulatory Issue Summary (RIS) 2016-07, “Containment Shell or Liner Moisture Barrier Inspection.” An NRC inspection in December 2003, identified an issue of very low safety significance (Green) that was treated as a Non-Cited Violation. During examination of the interior surfaces of the containment metal liner, the inspectors identified several areas with degraded coatings and rust on the containment liner at the interface of the metal liner and the bottom interior concrete floor. The inspectors also identified that the moisture barrier at the interface between the metal liner plate and interior concrete floor was degraded.

   During the evaluation and corrective actions, it was determined that the design of the Containment did not include a moisture barrier at the interface in question, and the material that was acting as a moisture barrier was silicone caulk that had been applied during liner coatings repair. The caulk was applied only in areas where the concrete had separated from the steel liner and was not continuous around the perimeter of the Containment. Work requests were submitted to remove the caulk and repair the concrete to eliminate the gaps between the concrete and the steel liner.

RIS 2016-07 noted the following:

- The original SPS design did not include a moisture barrier at the interface between the concrete floor and the steel liner.
- Subsequently, a moisture barrier was installed at this junction.
- The moisture barrier was later removed.

The RIS further stated that when the licensee reintroduced this configuration (no moisture barrier), an augmented examination (Examination Category E-C) should have been performed, or an evaluation should have been completed demonstrating why augmented examinations in accordance with ASME Code, Section XI, IWE-1241 were unnecessary.

In July 2017, a plant Containment Inservice Inspection (CISI) Basis Document was issued, which included a Technical Position that demonstrated why augmented examinations in accordance with ASME Code, Section XI, IWE-1241 were unnecessary:

As indicated in the CISI Basis Document, the Containment configuration includes a concrete containment with a steel liner and a concrete floor poured flush to the steel liner. The original design did not include a moisture barrier at the interface between the concrete floor and the steel liner. The concrete floor slab interface with the metal liner is included for examination and specifically identified as a separate item in the Units 1 & 2 CISI Program for IWE. The visual examination is performed each inspection period in accordance with the requirements of Examination Category E-A, for Item No.: E1.11, Accessible Surface Areas, which is exactly the same examination requirement as for Item No.: E1.30, Moisture Barriers. If surface areas are identified with indications of potential degradation and aging affects at this interface area, the affected surface areas will be evaluated. If the areas are determined to have accelerated degradation, then the subject areas will be included under Examination Category E-C, and examined accordingly. This examination evaluation method meets the examination requirements for the interface area at concrete to metal interfaces as described in NRC RIS 2016-07.

Currently, the Containment IWE ISI Plan identifies Examination Item No. E1.11A, “Accessible Surface Areas (Concrete Floor Slab to Metal Liner Interface)”, to be examined each inspection period. For the first period (in the third interval), the floor slab to metal liner interface surface in Item No. E1.11A will receive an augmented visual examination (VT-1) in accordance with Examination Category E-C. If the examination is acceptable, the frequency will revert back to examination under Category E-A using the General Visual examination technique.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In November 2017, as part of oversight review activities, the ISI Program - Containment Inspection Activity (UFSAR Section 18.2.12) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

7. In January 2018, an aging management program effectiveness review was conducted for the ISI Program - Containment Inspection Activity (UFSAR Section 18.2.12), which included the *ASME Section XI, Subsection IWE* program. Information from the summary of that effectiveness review is provided below:

   The ISI Program - Containment Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. The ISI Program - Containment Inspection Activity implements the inspection, testing and examination requirements including references to documents that implement repair/replacement activities of ASME Section XI, as required and conditioned by Title 10 Code of Federal Regulations (CFR) Part 50, Section 55a Codes and standards (10 CFR 50.55a). In addition to the normal IWE inspections which are performed once a period, inspections of the liner are performed every outage in accordance with station procedures by the ISI Program - Containment Inspection Activity personnel and by the stations coating engineer. These inspections along with the normal IWE inspections ensure that the liner, which is the final fission product barrier, remains capable of performing its design function and that any noted conditions that could affect containment integrity are promptly resolved.

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 manage the aging effects of manages cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness 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. 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, 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 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:

- Cracking
- Cracking; Loss of material
- Cracking and distortion
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking

The design of the reinforced concrete Containment does not utilize prestressing tendons.

For the current 10-year inspection interval (third quarter 2017 through second quarter 2027), IWL Containment Inservice Inspections (CISIs) 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 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 Code specified 12 months before the start of the inspection interval.

The program includes the accessible areas of the concrete dome and cylinder walls. The evaluations of these accessible areas provide the basis for extrapolation to the expected condition of inaccessible areas, and an assessment of potential degradation in such areas. The primary inspection method is visual examination (VT-1C, VT-3C) using the evaluation criteria provided in Chapter 5 of ACI 349.3R-02, “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-1968, “Guide for Conducting a Visual Inspection of Concrete in Service.”

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 (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). In 1988, a research study was performed to evaluate the degradation processes that could affect the reinforced concrete structures. Concrete core samples were secured from the intake canal, Unit 1 Condensate Storage Tank Missile Shield, Unit 2 Safeguards Building and Unit 2 Containment. Based on testing of these samples, the study concluded that there was no evidence of ASR.

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWL* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S2, ASME Section XI, Subsection IWL.

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):

Monitoring and Trending (Element 5)

1. Procedures will be revised to specify that inspection results be compared to previous results to identify changes from prior inspections, and that quantitative measurements are recorded and trended for applicable parameters monitored or inspected.

Acceptance Criteria (Element 6)

2. Procedures will be revised to specify that inspection results be compared to previous results to determine if degradation is passive for application of second-tier acceptance criteria as specified in ACI 349.3R-02, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September/November 2006, the five year ASME Code, Section XI, Subsection IWL Inspection of the Unit 2 concrete Containment was performed by the Responsible Engineer and identified areas that required further investigation, such as rock and sand pockets and embedded pieces of wood. Work orders were issued to remove the wood and clean the pockets down to sound material. The Responsible Engineer determined that, taken together or individually, the defects identified did not represent a significant structural concern. The Containment was determined to retain its ability to perform as designed under all load cases including the design basis earthquake and a postulated strike from a tornado generated missile.

2. In August 2011, prior to the next five year ASME Code, Section XI, Subsection IWL Inspection, a review of the Containment Structure Repair Plan and Evaluation identified numerous non-code, cosmetic repairs for the concrete Containment were identified as not being performed following excavation of the concrete in 2006 to determine the extent of defects. No noticeable rust staining had been evidenced at these locations and a more detailed IWL concrete inspection was scheduled for later that year (August/September 2011) with a crane and man basket. Work orders were issued and the non-code, cosmetic repairs of the Containment dome and shell were repaired in September 2012.

3. In September 2012, while performing cosmetic repairs to an area on the west side of Unit 2 Containment, suspect concrete was excavated down to the point that primary reinforcement was exposed. The area of exposed reinforcement measured 10 x 9 x 5 inches. Per ASME Code, Section IWL, this required a code repair. A work order was issued and this area of the Containment dome was repaired in October 2012.

4. In Fall 2012, while performing exterior concrete inspections on Unit 2 Containment in accordance with ASME Code, Section XI, Subsection IWL, on the southeast quadrant of the dome, efflorescence was found at the grouted edge below and to the south of the southeast lightning arrestor. The area was sounded with a hammer and a large area above the efflorescence sounded hollow. A vendor was contracted to perform scans of the suspect area. The areas of concern were surveyed using visual inspection, ground penetrating radar and impulse echo NDE techniques. The presence of what would appear to be delaminated concrete in the suspect region was reported. The depth of delamination extended only to depths between two to five inches from the surface (concrete cover) and there was no visual evidence of any reinforcing steel corrosion. Since the indications appeared to be within the concrete cover, a code repair was not required.

5. In July 2016, while performing Unit 1 Containment concrete inspection in accordance with ASME Code, Section XI, Subsection IWL, spall (3 x 8 x 1 inch deep) with loose material was identified above the Spring line in the Southeast quadrant of the dome. While this area is within the outermost layer of the reinforcing steel, rebar was not exposed. Based on the depth of the excavation area and a review of the ASME Code, Section XI, Subsection IWL Code, the repair was classified as an ASME code repair. A work order was issued and this area of the Containment dome was repaired in July 2016.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the ISI Program - Containment Inspection Activity (UFSAR Section 18.2.12) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was conducted for the ISI Program - Containment Inspection Activity (UFSAR Section 18.2.12), which included the *ASME Section XI, Subsection IWL* program. Information from the summary of that effectiveness review is provided below:

   The ISI Program - Containment Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. The ISI Program - Containment Inspection Activity implements the inspection, testing and examination requirements including references to documents that implement repair/replacement activities of ASME Section XI, as required and conditioned by Title 10 Code of Federal Regulations (CFR) Part 50, Section 55a Codes and standards (10 CFR 50.55a). These inspections, which are performed in accordance with station procedures by the ISI Program - Containment Inspection Activity personnel, ensure that the concrete Containment remains capable of performing its design function and that any noted conditions that could affect containment integrity are promptly resolved.

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, VT-1C) to manage aging effects for containment concrete, 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. 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, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWL* 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.

B2.1.31 ASME Section XI, Subsection IWF

Program Description

The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that manages loss of material, cracking, loss of preload, and loss of mechanical function for supports of Classes 1, 2, and 3 piping and components. There are no Class MC supports at SPS.

During the fifth inservice inspection interval (December 2013 to October 2023), inspections of supports for Class 1, 2, and 3 piping and components are performed consistent with the 2004 edition of ASME Code, Section XI, as approved 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 latest edition and addenda of the Code specified 12 months before the start of the inspection interval. ASME Code edition will be used consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation.

Supports for Class 1, 2, and 3 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, Article 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 Subsection IWF 3000, that support is reexamined 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 criteria of Subsection IWF 3400 are extended to include additional examinations in accordance with Subsection IWF 2430. The ASME Code, Section XI, Subsection IWF program provides a systematic method for periodic examination of supports for Class 1, 2, and 3 piping and components. The primary inspection method is visual examination. The instructions and acceptance criteria for the visual examinations (VT-3) are included in existing procedures.

If a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, then the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

The requirements of subsection IWF are supplemented to include monitoring of high-strength bolting (actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi) or 1,034 megapascals (MPa) and greater than one inch nominal diameter), with volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material/environment combination) up to a maximum of 25 bolts.

Procedures will 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used.

This program 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.

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWF* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S3, ASME Section XI, Subsection IWF.

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):

Scope of Program (Element 1)

1. Procedures will be enhanced to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

Preventive Actions (Element 2)

2. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants will be in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339.

3. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication, “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” will be used.

Parameters Monitored or Inspected (Element 3)

4. Procedures will be revised to specify that for NSSS component supports, Class 1 high strength bolting greater than one inch nominal diameter, including ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), will be monitored for SCC.

Detection of Aging Effects (Element 4)

5. Procedures 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.
6. Procedures will be revised to specify that, for NSSS component supports, high-strength bolting greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2013, during an ASME Code inspection, corrosion was identified on the top horizontal 3 x 3 inch angle of a service water system pipe support in Unit 1. The gap listed for this area of the pipe support could not be determined. This was considered an ASME Code, Section XI rejectable indication. Engineering inspected the angle to quantify the material loss so that it could be evaluated. Engineering evaluation determined the mild surface rust observed is negligible. The hanger meets all its design basis requirements and remains fully functional and fully qualified in this as-found condition. This condition does not represent any loss of support function for this pipe support. The support drawing has been revised to include a note to reflect the minor material loss. The support was determined to be functional by evaluation; therefore, no scope expansion is required.
2. In May 2014, during an expanded scope examination determined consistent with Subsection IWF-2430, observed indications deemed not acceptable were found and documented with a support associated with a recirculation pump in Unit 2. Specifically, one nut was found not flush tight to the support plate and unable to be moved by hand. Two other studs were found to have been flame cut, one of which still has part of the nut still on the stud. The examination was an expanded scope examination due to missing bolts/nuts discovered during a previous examination in April 2014. The missing bolts/nuts were replaced and the inspection scope was expanded. Engineering evaluation of the condition identified in the expanded inspection determined the support was functional as-found and the loose nut was tightened.
3. In May 2014, during an NDE/ISI examination in the Unit 2 Pressurizer Relief Tank Room, the inner bolt on both sides of the pipe clamp were found not tight against the side of the clamp. With some pressure, the bolts could be moved side to side but could not be rotated in their holes. The pipe clamp could not be rotated on the pipe. This condition was document on the NDE report and was found to be rejectable. This support was examined as part of the ASME Code, Section XI NDE/ISI scope for the 2014 Unit 2 refueling outage. Engineering evaluation in accordance with Subsection IWF-3122 (acceptance by correction or acceptance by evaluation) determined the support was functional. The support was determined to be functional by evaluation; therefore, no scope expansion is required.
4. In December 2015, an effectiveness review of the In-service Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In November 2017, as part of oversight review activities, the In-service Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

7. In January 2018, an aging management program effectiveness review was conducted for the In-Service Inspection (ISI) Program - Component and Component Support Inspections Activity (UFSAR Section 18.2.11), which includes the inspection of *ASME Section XI, Subsection IWF* program. Information from the summary of that effectiveness review is provided below:

   The In-Service Inspection (ISI) Program - Component and Component Support Inspections Activity is meeting or exceeding the requirements consistent with the selected elements of NEI 14-12, “Aging Management Program Effectiveness.” Key activities of the AMA that were reviewed include the performance of (non-destructive examinations) NDE to meet the requirements of ASME Code, Section XI and AMA document updates. An ASME Section XI Program is required by the Code of Federal Regulations. A 10-year period (July 2006 to June 2016) of condition reports and engineering evaluations has been reviewed to identify programmatic issues. No programmatic issues were identified as a result of this review.

   ISI examinations are scheduled appropriately in the Unit 1 ISI Schedule (Unit 1, Inservice Inspection Schedule, Fifth Inspection Interval, December 14, 2013 to October 13, 2023) and the Unit 2 ISI Schedule (Unit 2, Inservice Inspection Schedule, Fifth Inspection Interval, May 10, 2014 to May 9, 2024) to meet the requirements of ASME Code, Section XI and the Code of Federal Regulations. The Period 1, Fifth Interval ISI examinations have been completed to meet the ASME Section XI Code requirements. The ISI plan and the ISI schedule are updated periodically to implement new code cases of benefit and new rules and regulations, as required. There have been no new issues revealing service induced degradation to date in the fifth Interval.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWF* program includes activities to perform visual examinations (VT-1, VT-3) and volumetric examinations to manage loss of material, cracking, loss of preload, and loss of mechanical function for supports of Classes 1, 2, and 3 piping and components, 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. 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWF* 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.

B2.1.32 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; Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program”; and NEI 94-01, Rev. 3A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR 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 10 CFR Part 50, Appendix J. 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 (B2.1.29) and the *ASME Section XI, Subsection IWL* program (B2.1.30), augment the *10 CFR Part 50, Appendix J* program (B2.1.32) leakage rate testing and detect evidence of structural degradation that may affect the Containment structure leakage integrity.

Aging effects associated with components excluded from leak rate testing are managed by the:

- *Water Chemistry* program (B2.1.2)
- *Open-Cycle Cooling Water System* program (B2.1.11)
- *Closed Treated Water Systems* program (B2.1.12)
- *One-Time Inspection* program (B2.1.20)
- *External Surfaces Monitoring of Mechanical Components* program (B2.1.23)

NUREG-2191 Consistency

The *10 CFR Part 50, Appendix J* program is an existing program and 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2013, a license amendment request (LAR) was submitted to implement Option B of 10 CFR Part 50, Appendix J for both Units 1 and 2. The LAR included results of the three previous Type A tests for each unit. For Unit 1, the results were: May 2006 - 0.298 of allowable leakage (L_a); April 1992 - 0.386 of L_a; June 1988 - 0.314 of L_a. For Unit 2, the results were: October 2000 - 0.06 of L_a; May 1991 - 0.418 of L_a, November 1986 - 0.638 of L_a.

   In the safety evaluation report (SER) issued with the approved license amendments, the NRC found that the results of the Integrated Leak Rate Test (ILRT) and Local Leak Rate Test (LLRT) programs demonstrated acceptable performance of the primary Containment and demonstrated that the leak-tight integrity of the primary Containment was adequately managed. The SER further found that the Containment leakage rate testing program and supplemental inspections were adequate to periodically examine, monitor, and manage age-related and environmental degradation of the primary Containment.

   The Type A test data provided objective evidence that the *10 CFR Part 50, Appendix J* program effectively managed leakage through the Containment, and systems and components penetrating the Containment to ensure that the leakage rate did not exceed allowable leakage rate values as specified in the Technical Specifications or associated Bases.

2. In May 2014, during Type B testing, excessive leakage was discovered coming from under an adjustment nut in electrical penetration 18B on Unit 2. The measured leak rate did not exceed 0.6 L_a. The midlock cap was torqued to specification and the as-left leak rate was acceptable.

3. In November 2015, the most recent Type A test for Unit 2 was performed. Results of the Type A test found that leakage was 0.063 of L_a. This leak rate is consistent with the previous leakage rate of 0.06 of L_a from October 2000, indicating not only that equipment is being adequately maintained, but also that equipment maintenance has been capable of creating a significant safety margin between the technical specification allowable limits and the as-tested values. Test results show the effects of aging are effectively being managed for the Containment building.

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 the loss of material, loss of sealing, loss of leak tightness, loss of preload, and cracking 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 loss of intended function.

Conclusion

The continued implementation of the *10 CFR Part 50, Appendix J* 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.

B2.1.33 Masonry Walls

Program Description

The *Masonry Walls* program is an existing condition monitoring program that manages loss of material, cracking, and loss of material (spalling and scaling) for masonry walls. The *Masonry Walls* program is implemented as part of the *Structures Monitoring* program (B2.1.34).

The *Masonry Walls* program consists of inspections, consistent with IE Bulletin 80-11 (IEB 80-11), “Masonry Wall Design,” and plant-specific monitoring proposed by IN 87-67, “Lessons Learned from Regional Inspections of Licensee Actions to IE Bulletin 80-11,” 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, conducted by qualified personnel at a frequency not to 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 for each masonry wall remains valid during the subsequent period of extended operation.

Qualifications for personnel performing inspections and evaluations are consistent with ACI 349.3R-02, “Evaluation of Existing Nuclear Safety-Related Concrete Structures”. 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 documented and entered into the Corrective Action Program for evaluation which will result in analysis, repair or replacement.

Masonry walls that are considered fire barriers are also managed by the *Fire Protection* program (B2.1.15). Steel elements of masonry walls are visually inspected by the *Structures Monitoring* program (B2.1.34).

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

Detection of Aging Effects (Element 4)

1. Procedures will be revised to clarify qualifications for personnel performing inspections of masonry walls and concrete to be consistent with ACI 349.3R-02.

Monitoring and Trending (Element 5)

2. Procedures will be revised to explicitly address the trending of inspection results and projection to the next inspection interval. The procedure will be revised to include acceptance criteria for masonry wall inspections that will be used to ensure observed aging effects (cracking, loss of material, or gaps between the structural steel supports and masonry walls) do not invalidate the evaluation basis of the wall or impact its intended function.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2009, during a walkdown of the Unit 1 Normal Switchgear Room a crack was identified around a concrete block wall. Inspection of the opposite side of the wall showed that the same crack existed on the Unit 2 side. The crack was less than 1/8 inch wide on both sides. The crack was repaired by work order, which was completed and accepted on 5/26/2009.
2. In June 2012, while performing inspections, a 0.050 inch crack was observed in the masonry block and mortar of the Unit 1 ‘A’ Fuel Oil Pump House exterior. The crack width decreased to 0.025 inch between the mortar and the masonry as it progressed along the west wall to the south wall. A work order was issued and the wall crack was repaired.
3. In May 2015, an approximate 1/2 inch diameter hole was identified in a masonry block wall which is located between Battery Room 1A and the Unit 1 Emergency Switchgear Room. This wall is a fire barrier wall. The hole did not completely penetrate the block wall and may have been created for an anchor bolt that has since been removed. A work order was submitted and the hole in the block wall was repaired.

The above examples of operating experience provide objective evidence that the *Masonry Walls* program includes activities to perform visual inspections to manage loss of material, cracking, 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, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Masonry Walls* 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.

B2.1.34 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 material
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material, change in material properties
- 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 U.S. Nuclear Regulatory Commission (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 scope of the *Structures Monitoring* program includes structures and components in the scope of subsequent license renewal. The program relies on periodic visual inspections to monitor and maintain the condition of structures and components within the scope of subsequent license renewal. Inspections are conducted by qualified personnel at a frequency not to exceed five years, except for wooden poles, which will be inspected on a 10-year frequency. The interval between successive recurring inspections may be decreased based on conditions discovered in previous inspections.

Structural monitoring inspections consist primarily of periodic visual examination of accessible structures and components performed by qualified personnel. 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 is based on the guidance provided in the 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 will include preventive actions to provide reasonable assurance of structural bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067, “Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel,” and TR-104213, “Bolted Joint Maintenance & Application Guide”), American Society for Testing and Materials (ASTM) standards, and AISC specifications, as applicable.

In order to evaluate the potential of water to cause degradation of inaccessible below-grade concrete, samples of groundwater will be 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, inaccessible areas are assessed for aging when aging degradation exists in accessible areas and opportunistically inspected when excavated.

Ground water monitoring has shown the ground water to be non-aggressive, except for one sampling point. In 2007, a sample with a significantly high chloride level was obtained from the Turbine Building sump. Subsequent sample results from this sump have found additional chloride levels above the acceptance limit. An inspection was performed to assess the structure for any degradation that could be attributed to the elevated levels of chloride. The inspection found no evidence of significant degradation. There have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant. Engineering continues quarterly monitoring of the ground water in this sump.

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.

Concrete inspection results are evaluated to identify changes that could be indicative of Alkali-Silica Reaction (ASR) development. 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 (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). In 1988, a research study was performed to evaluate the degradation processes that could affect the reinforced concrete structures. Concrete core samples were secured from the intake canal, Unit 1 Condensate Storage Tank Missile Shield, Unit 2 Safeguards Building and Unit 2 Containment. Based on testing of these samples, the study concluded that there was no evidence of ASR.

Structural sealants, seismic gap joint filler, vibration isolation elements, and other elastomeric materials are 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 is supplemented by tactile inspection to detect hardening if the intended function is suspect.

Procedures will 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used.

Spent fuel pool (SFP) liner leakage through the leak chase channels is monitored. An alarm is provided on the SFP to sound at a level loss of approximately 0.5 feet (UFSAR Section 9.5.3.3). A review of recent leak chase channel monitoring reports shows acceptable leakage rates with no tell-tale drains being completely blocked.

The *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35) are 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 enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop.

Preventive Actions (Element 2)

2. Procedures will be revised to 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used.

Detection of Aging Effects (Element 4)

3. Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002.
4. Procedures will be revised to inspect wooden power poles on a 10-year frequency.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2007, a condition report (CR) was written to document a ground water monitoring sample with a chloride level of 1210 ppm, which exceeded the acceptance limit of <500 ppm. This sample was obtained from the Turbine Building sump. Corporate and site Engineering continue to monitor the quarterly sample results from the Turbine Building sump and have found additional chloride levels above the acceptance limit, as high as 2700 ppm. An inspection of the Turbine Building sump was performed in July 2008 to assess the sump structure for any degradation that could be attributed to the elevated level of chlorides. The inspection found no evidence of significant degradation to the interior concrete. There are no safety-related components in the vicinity of the Turbine Building sump, and there have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant.

The source of the chlorides has not been determined. The Turbine Building sump is the deepest dewatering point and closest to the Intake Canal where expected underground leakage from the canal could influence the chloride level. The potential for in-plant sources of chlorides reaching the sump via secondary drains or local ground water was studied and determined to be unlikely. An Engineering evaluation concluded that, while the chloride level has remained high in the Turbine Building sump, the other sumps/piezometer well locations, some of which are located in close proximity to the Turbine Building sump, have been found to be consistently within acceptable levels. Engineering will continue to monitor the chloride levels in the Turbine Building sump on a quarterly basis. The plant procedure has been revised to maintain sampling requirements so that trending may continue but eliminate the comparison to the acceptance criterion for this sampling point.

2. In May 2011, a spall was found on the inside concrete surface of the bioshield wall of the Unit 2 Containment ‘C’ steam generator cubicle. The spall was approximately six inches long by six inches wide and 1-1/4 inches deep. The reinforcing steel was not exposed. It was determined that the bioshield wall remained fully functional, but the spalled concrete required repair prior to unit startup to prevent potential degradation of the reinforcing steel. A work order was submitted and the spalled concrete has been repaired.
3. In December 2011, several embedded anchor bolts for the condenser unit of a Unit 1 Control Room chiller were found to be degraded. The anchor bolts displayed signs of corrosion and material loss. A work order was submitted and the anchor bolts were repaired in December 2011, which consisted of chipping the existing concrete around the anchor bolts until sound metal was reached, performing a weld repair of each anchor bolt, and repairing the concrete slab.
4. In October 2012, leakage (approximately one gpm) was identified in the bottom portion of the steel to concrete joint (interface between the steel elbow and the concrete pipe) of the Unit 2 ‘D’ 96-inch circulating water line. Corrosion and coating failure on the bottom third of the pipe was observed at this location. The urethane seal around the leading (upstream) edge of the joint was also missing and degraded. A work order was submitted and the Unit 2 ‘D’ 96-inch circulating water line joint has been repaired.
5. In January 2013, the Service Building roof was leaking, causing water to collect in two locations on the floor of the Service Building hallway. The first location was near the #1 EDG room. The second location was approximately halfway between the doors to the health physics area and the door to the operations annex. A work order was submitted and degraded roof areas were repaired.

6. In December 2014, a CR was written to document a ground water monitoring sample that showed a chloride level of 610 ppm. The sampling point that exhibited unacceptable chloride levels is located adjacent to the Intake Canal, which draws water from the river. Three months later the same sampling point was found to have chlorides at 676 ppm. These values exceeded the acceptance limit of <500 ppm. The CR evaluation determined that the elevated chloride level was probably due to unusually low rain fall on the James River, temporarily increasing its natural salinity. Results from subsequent monitoring of ground water have been acceptable, and no degradation of concrete due to elevated chloride levels has been identified.
7. In December 2015, an effectiveness review of the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.
8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
9. In November 2017, as part of oversight review activities, the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) AMA owners confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments required in UFSAR Chapter 18. Security lighting poles were within the scope of license renewal but were not inspected during the Civil Engineering Structural Inspection Activity cycle completed in 2012. The omission of the security lighting poles from the 2012 inspection cycle was entered in the Corrective Action Program. In December 2017, Civil Engineering inspected the light poles and noted no degradation. The License Renewal Application and supporting documentation were reviewed for in-scope structures requiring inspection, and that information was cross-referenced with the implementing procedure to confirm aging management program commitments required by UFSAR Chapter 18 were satisfied. The security lighting poles are identified in the implementing procedure as being within scope of license renewal and will be inspected during subsequent structural inspections.

10. In January 2018, an aging management program effectiveness review was conducted for the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6), which include the *Structures Monitoring* program (B2.1.34), *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). Information from the summary of that effectiveness review is provided below:

    The Civil Engineering Structural Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the AMA that were reviewed included structural inspections for aging management that have been incorporated into the periodic inspections performed for Maintenance Rule compliance. Maintenance Rule inspections, along with trending and evaluation for evidence of aging effects, ensure the continuing capability of civil engineering structures to meet their intended functions consistent with the current licensing basis. A 10-year review of inspection results and corrective actions did not identify any aging that resulted in a loss of intended function(s).

11. In March 2018, the existing Structures Monitoring program was revised to improve the inspection techniques and to adopt new inspection techniques to manage aging effects associated with ASR degradation of concrete structures and components consistent with industry operating experience IE Notice 2011-20 (IN 2011-20), “Concrete Degradation by Alkali-Silica Reaction,” and EPRI Report #3002005389 (2015), “Tools for Early Detection of ASR in Concrete Structures.”

The above examples of operating experience provide objective evidence that the *Structures Monitoring* program includes activities to perform volumetric and visual inspections 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 manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Structures Monitoring* 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.

B2.1.35 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 that manages the following aging effects:

- Cracking
- Cracking; blistering
- Cracking; blistering; loss of material
- 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

This program consists of inspection and surveillance of raw water control structures associated with emergency cooling systems or flood protection, which are the Discharge Canal, Intake Canal, Discharge Tunnel and Seal Pit, High Level Intake Structure, and the Low Level Intake Structure. Surry Power Station is not currently committed to the requirements of Regulatory Guide 1.127, Revision 1 (March 1978), "Inspection of Water-Control Structures Associated with Nuclear Power Plants," for the structures in-scope for subsequent license renewal. The *Inspection of Water Control Structures Associated with Nuclear Power Plants* program is consistent with Section C2 of Regulatory Guide 1.127, Revision 1 and relies on periodic visual inspections conducted by qualified personnel 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 also includes structural steel and structural bolting associated with water control structures. Periodic underwater inspections of the Intake Canal are performed by divers to identify concrete liner degradation and accumulation of debris. Any findings of degradation or debris are entered into the Corrective Action Program.

Qualifications for personnel performing inspections and evaluations are consistent with ACI 349.3R-02, "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. Quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Conditions found to impact the intended function of the water control structure are documented and entered into the Corrective Action Program for evaluation which will result in analysis, repair or replacement. The evaluation of the results of the inspection determines whether the discovered deficiency is minor and will not threaten the structure’s ability to perform its intended function until the next scheduled inspection. A significant deficiency requires corrective action and/or more frequent monitoring to ensure that the structure will remain functional until the next regularly scheduled inspection.

In order to evaluate the potential of water to cause degradation of inaccessible below-grade 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, inaccessible areas are assessed for aging when aging degradation exists in accessible areas and opportunistically inspected when excavated.

There are no dams within the scope of the program.

The *Inspection of Water Control Structures Associated with Nuclear Power Plants* program is implemented as part of the *Structures Monitoring* program (B2.1.34).

Procedures will 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used.

Concrete inspectors will be 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 (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). In 1988, a research study was performed to evaluate the degradation processes that could affect the reinforced concrete structures. Concrete core samples were secured from the intake canal, Unit 1 Condensate Storage Tank Missile Shield, Unit 2 Safeguards Building and Unit 2 Containment. Based on testing of these samples, the study concluded that there was no evidence of ASR.

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 enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Procedures will be revised to provide guidance for specification of bolting material, lubricants and sealants, and installation torque or tension to prevent degradation and assure structural bolting integrity.
2. Procedures will be revised to specify the preventive actions for storage discussed in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts” for ASTM A325, ASTM F1852, ASTM F2280, and/or ASTM A490 structural bolts.

Detection of Aging Effects (Element 4)

3. Procedures will be revised for concrete inspection to require at least five years of experience (or ACI inspector certification) to be consistent with ACI 349.3R-2002.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2007, underwater inspection of Intake Canal concrete liner was conducted using divers. A number of minor defects were identified in the concrete liner, and an accumulation of sand, silt, shell, and debris was identified throughout the Intake Canal bottom. This material varies in depth from no debris (immediately in front of the Unit 2 High Level Intake Structure) to ten feet of material (upstream of the Low Level Intake Structure). The total accumulation of material is estimated at equivalent to two feet across the entire Intake Canal bottom or 582,000 cubic feet.

   Design Engineering evaluated the findings and concluded the Intake Canal is degraded but continues to perform its design function. The concrete liner defects are relatively minor and with the exception of the small sections of missing liner, the underlying soil continues to be protected from erosion. The void size at these locations does not represent a significant loss of material. No potential for gross loss of canal inventory exists.

The accumulation of material across the bottom of the intake canal does not represent a significant inventory concern. This conclusion is based upon review of calculations and discussions with the design basis calculation originator. The ability of the Intake Canal to deliver a sufficient flow of cooling water to plant systems/components is dependent upon the reservoir of water above the minimum calculated water elevation versus the total quantity of water contained within the canal (i.e., provided the silting in of the canal does not encroach upon the minimum calculated water elevation of 18.4 feet an inventory concern does not exist). The average canal concrete bottom is elevation 5.90 feet. Raising the average canal bottom to elevation 7.90 feet due to silting does not adversely impact the Intake Canal design basis.

2. In November 2009, during the annual inspection of the Intake Canal liner, a liner defect was identified. The defect was located on the north side of the canal. A work order was submitted and the canal liner defect was repaired in July 2011.

3. In May 2015, inspection of the high level intake structure (HLIS) discovered concrete cracking and exposed rebar. Engineering evaluated the condition and determined that the crack was of sufficient length and configuration to be of concern that a portion of the concrete could dislodge and fall into the bay, potentially challenging the functionality of the trash rack. The condition was reported through the Corrective Action Program and a repair was made during the outage to ensure no loss of intended function.

4. In February 2017, the annual Intake Canal liner visual inspection was completed. Several issues were identified during the inspection. Some of the concrete liner panels have small broken sections and in some cases these broken pieces have settled or shifted. The loss of fill material behind the broken pieces of panel has created small pockets of voids behind the concrete panels. There was some minor spalling noted that exposes the reinforcing steel mesh in some areas. The expansion joints were last sealed in 2008, and not all of the joints were sealed at that time. The defects noted in this inspection are minor and the Intake Canal is capable of performing its design basis function for all design basis events. The Intake Canal liner and expansion joint defects were reported through the Corrective Action Program and have been entered in the Capital Living Plan for annual evaluation of work planning and funding priorities.

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 loss of intended function.

Conclusion

The continued implementation of the *Inspection of Water Control Structures Associated with Nuclear Power Plants* 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.

B2.1.36 Protective Coating Monitoring and Maintenance

Program Description

The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. The program manages coating system selection, application, visual inspections, assessments, repairs, and maintenance of Service Level I protective coatings as defined in RG 1.54 Revision 2, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants”.

Maintenance of 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 Containment by performing visual inspections with qualified inspectors to ensure there is no coating degradation.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside Containment (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, but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liner and components. 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 amount of unqualified coatings. Unqualified coating may fail in a way to affect 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 primary containment is kept within acceptable design limits to support the post-accident operability of the ECCS.

NUREG-2191 Consistency

The *Protective Coating Monitoring and Maintenance* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S8, Protective Coating Monitoring and Maintenance.

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):

Monitoring and Trending (Element 5)

1. Procedures will be revised to require that a pre-inspection review of the previous “two” condition assessment reports be performed prior to each refueling outage.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2006, during an Engineering walkdown, Service Level I coating degradation and external corrosion was observed on a Unit 1 component cooling pipe inside Containment at the penetration area. Engineering selected two eighteen inch lines and two six inch lines with the most external corrosion for non-destructive examination (NDE) inspection. The identified pipes were cleaned and an NDE inspection measured the wall thickness to be greater than minimum wall thickness. Based on the results, no repair of the component cooling pipe was recommended. Work orders were created to restore the coating. On-going walkdowns performed routinely by the system engineer identified general corrosion and coating degradation of the component cooling piping throughout both Containments.

   Due to the extent of the degradation of Service Level I coatings on component cooling piping identified in October 2006, Engineering developed a program for monitoring and trending component cooling piping external corrosion rates. A separate prioritized action plan was developed for each unit. To maintain a meaningful component cooling pipe monitoring program, the component cooling pipe coating inside both Containments was restored to retard the continuing and accelerating pipe degradation, preserve the remaining component cooling pipe wall thickness, and assure long term component cooling pipe integrity. The Management Plan developed and funded a component cooling pipe and pipe coating restoration project so that a subsequent meaningful monitoring plan could be established. The restoration project was completed in June 2008.

2. In November 2009, coating inspections of the Containment steel liner were performed during the Unit 2 refueling outage (RFO). In general, the containment steel liner condition showed little mechanical damage. No degradation of the steel liner itself was noted during these inspections. There was very little Service Level I coating failure on the concrete surfaces in RCP cubicle ‘B', Pressurizer Cubicle, and Loop Rooms. Degraded Service Level I coatings

were observed on component cooling piping. The subsequent inspections and Containment walkdowns were performed May 2011 during the Unit 2 RFO. An engineering walkdown was performed and the steel liner steel required coatings to be applied at various locations. Unqualified coatings were identified on the basement concrete joints in the form of spray paint at various locations. Unqualified coating was removed from the basement joint material resulting in a reduction of unqualified coating margin. The Containment Service Level I coating repairs were completed during the refueling outage.

3. In July 2012, during RFO 1R25, various areas of the Unit 1 Containment steel liner required coating repairs on each elevation. The Unit 1 coatings condition assessment was completed during RFO 1R24 and concluded there were no noticeable changes in the general condition from the condition noted during the fall 2010 refueling outage inspection. A walkdown of the coatings and steel liner in the Unit 1 Containment was performed by Engineering, which included a Coating Specialist and an ASME Code, Section XI, Subsection IWE, program Engineer. No relevant Service Level I coating indications were noted on the Containment liner or other surfaces with Service Level 1 coating that would affect the intended function of the ECCS suction strainers. The Containment steel liner Service Level I coatings repairs were completed in November 2013. The April 2015 Unit 1 R26 refueling outage Containment Coatings Assessment identified the Containment steel liner requires coating repairs be performed at various locations. The damaged areas were the result of mechanical damage.

4. In November 2015, during the Unit 2 refueling outage, visual examination of the Containment steel liner, along the concrete-liner interface of the Unit 2 Containment, was performed per ASME Code, Section XI, Subsection IWE. Areas with degraded Service Level I coatings were identified on the concrete-liner interface along the back of the Containment sump. Coated areas were examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. The VT-1 examination did not reveal any adverse condition other than surface corrosion in the area identified. The Service Level I coating repairs in the Containment sump were completed in December 2015. A follow-up inspection of the Service Level I coating repair to the Containment steel liner to concrete floor interface identified two areas behind the inside recirculation spray pump suction header supports which required further Service Level I coatings repair. This was not a functionality issue. These were considered cosmetic issues proven by the completed satisfactory NDE examinations using UT thickness measurements technique and visual examination (VT-1) which did not reveal any adverse condition other than surface corrosion in the area identified. The Containment steel liner Service Level I coatings repairs were completed in November 2015. A Containment Coatings Walkdown was performed during the Spring Unit 2 2017 refueling outage. There were no noticeable changes in the general condition from the condition noted during the Fall 2015 refueling outage. The liner along various elevations continues to display marred sites to bare metal as the result of mechanical damage.

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, 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, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Protective Coating Monitoring and Maintenance* 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.

B2.1.37 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 the aging effect of 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.

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 is performed 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 enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3)

1. A new procedure will be developed that will include guidance for the identification of adverse localized environments of temperature, moisture, radiation, contamination, and oxygen.

Detection of Aging Effects (Element 4)

2. A new procedure will be developed that includes 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.
3. A new procedure will be developed that includes an inspection frequency of at least once every ten years.

Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4)

4. A new procedure will be developed that includes the addition of jacket surface and connection covering material anomalies including embrittlement, melting, swelling, and surface contamination.

5. A new procedure will be developed that includes the performance of a review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.

Acceptance Criteria (Element 6)

6. A new procedure will be developed that describes acceptance criteria for both tests and visual inspections of the electrical cable and connection insulation material.

Corrective Actions (Element 7)

7. A new procedure will be developed that includes 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 has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Between August 2004 and November 2006, baseline visual inspections of cables and connections were performed as required by the initial renewed operating license. The scope of the inspection included electrical cable jackets and connector coverings. In accordance with the procedure, the visual inspection was performed only for cables and connectors that were completely accessible. There was no use of ladders, opening of junction boxes, or removal of cable tray covers.

   During the inspections, cracking in the jackets of electrical cables was observed in the following three instances:

   a. On the Turbine Building operating deck, the cables located on the Unit 1 side just outside the normal switchgear room and supplying power from the station service transformers had circumferential cracking in the outer jacket. Based on a laboratory report on similar Unit 2 cables, this condition was determined to be due to elevated temperatures and improper vulcanizing of the jacket material. However, it was not a concern for cable integrity due to the type of construction of the cable. A Mylar wrap between the cable insulation and the jacket prevents propagation of the external jacket cracks through the insulation. These cables were replaced in 2012.

   b. The second observation involved minor cracking that was noted on a cable jacket located in the overhead area of the Unit 1 normal switchgear room. This observation was similar to the cracking on the cable on the turbine building operating deck and does not present a concern with respect to the insulation effectiveness of the cable.

   c. The cables involved with the third observation ran from the secondary side of the station service transformer to a 4160-volt switchgear cubicle. The observed portions of these cables are located outdoors below a covered cable tray between the transformer and the turbine building. The cable jackets are gray in color due to a combination of dirt and ultraviolet exposure. The jackets exhibited some minor longitudinal cracks. The condition of these jackets is consistent with what would be expected for long-term ultraviolet exposure. No concern regarding cable integrity resulted from this observation. These cables were replaced in 2012.

2. Between March 2015 and April 2016, the ten-year walkdown and visual inspection of cables and connections was performed. The scope of the inspection included electrical cable jackets and connector coverings. In accordance with the procedure, the visual inspection was performed only for cables and connectors that were accessible. There was no use of ladders, opening of junction boxes, or removal of cable tray covers.

   Based on field observations during the above walkdowns (outer cable jacket anomalies including cracking/discoloration/minor abrasions), it was recommended that several cables (nine) be reviewed to determine design parameters and if any further actions were required. These identified field observations indicated long term aging conditions, but did not identify any conditions where design functions were adversely affected.

   No damage was identified to the conductor material or the insulation that represents a problem for the operation of the cable. The discoloration, cuts, and cracking in the outer protective jackets do not affect the cable ampacity or insulation resistance. The jacket is not part of the cable insulation but does help extend the life of the cable by protecting the insulation. Engineering considered these cables to be functional in their current condition.

   Based on the engineering walkdowns, satisfactory environmental conditions, and the design reviews performed where warranted, there were no further corrective actions required or recommended.

3. In December 2015, an effectiveness review of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the detection of Aging Effects, Corrective Actions, and Operating Experience activity elements. The Non-Environmental Qualification (EQ) Cable Monitoring AMA includes elements of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

   Two gaps were identified during the evaluation for *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37). The first issue identified was that the license renewal inspection procedure did not include sufficient guidance to document consistent inspections. A procedure upgrade was recommended and implemented the following year to provide more detail on locations that are to be walked down during cable inspection activities. The second issue identified an inconsistency with walkdown frequency between license renewal documents and UFSAR

Section 18.1.4. The license renewal background document, the NRC SER for license renewal, and RAI responses called for an inspection between license year thirty and the end of the initial operating license and at least once per ten years during the period of extended operation. This allowed for the start of the period of extended operation as the beginning of the 10-year interval. UFSAR Section 18.1.4 states that subsequent inspections to confirm ambient conditions will be performed at least once per ten years following the initial inspection. Surry Power Station resolved the inconsistency by creating a recurring work order for a 10-year inspection that is based on completion of the initial inspection in 2006. The first 10-year inspection during the period of extended operation was completed on 10/04/2016 within the 10-year due date of 11/28/2016. Results of the December 2015 effectiveness review for the other two associated aging management programs are provided in the SLRA sections indicated above.

4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

5. In November 2017, as part of oversight review activities, the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

6. In January 2018, an aging management program effectiveness review was performed of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4). Information from the summary of that effectiveness review is provided below:

   The implementing procedure for this activity includes instructions for the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39). This effectiveness review summary applies to the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37).

The Non-Environmental Qualification (EQ) Cable Monitoring Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the AMA that were reviewed included the selection of components to be inspected or tested, the inspection and testing of the components, the evaluation of the inspection and testing results, repair/replacements of components as required, and AMA document updates. Engineering reports from the 2004/2006 and 2014/2016 accessible cable and connection inspection walkdowns were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed condition. The review also encompassed pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of cables and connections for those components within the scope of license renewal.

Cable reliability strategies have been implemented as follows: The Station Service Transformer secondary cables (medium-voltage) were replaced in 2012, primarily due to indicated jacket cracking and water intrusion at the secondary leads box. Replacement of the RSST 'C' secondary cables (medium-voltage) is planned due to North Anna OE concerning inadequate vertical support. These major projects have and will ensure the continued reliability of medium-voltage cables.

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 the aging effect of 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, 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.

B2.1.38 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 the aging effects of reduced electrical insulation resistance of the electrical cables and connections (cable system) insulation material subject to 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 (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, high voltage, low-level current signals because a reduced IR may contribute to signal inaccuracies.

The program applies to the containment high range radiation monitor system, the post-accident neutron monitoring system, and the excore neutron monitoring system.

The containment high range radiation monitor system cables are connected during calibration. Therefore, the calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation material aging degradation. The reviews are completed prior to the subsequent period of extended operation and at least every ten years thereafter.

The excore neutron monitoring system cables are disconnected during calibration. The program performs a proven cable test for detecting deterioration of the cable system insulation material. The test frequency is based on engineering evaluation and is performed at least once every ten years.

The post-accident neutron monitoring system cables are disconnected during calibration. The program will perform a proven cable test for detecting deterioration of the cable system insulation material. The tests will be completed prior to the subsequent period of extended operation and at least every ten years thereafter.

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, following enhancement, will be 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

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)

1. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment to evaluate reduced electrical insulation resistance by measuring cable resistance and capacitance.

Detection of Aging Effects (Element 4)

2. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes recommendations for types of electrical insulation tests including insulation resistance tests, time domain reflectometry tests, or other tests judged to be effective in determining cable system insulation physical, mechanical, and chemical properties.
3. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes a test frequency of at least once every ten years with the first test completed prior to the subsequent period of extended operation.

Acceptance Criteria (Element 6)

4. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment that includes acceptance criteria for the recommended test methods.

Corrective Actions (Element 7)

5. A new procedure will be developed for testing the post-accident neutron monitoring system cables and connections external to containment. The new procedure will include corrective actions and a requirement for an engineering evaluation to be performed when acceptance criteria are not met. The engineering evaluation will include a determination of whether the test frequency needs to be increased.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2012, the Unit 1 intermediate range channel N35 field cable insulation resistances were tested in accordance with an I&C procedure. From the Control Room, the measured signal for the cable center wire to inner shield for Channel N35 was found to be slightly below the minimum acceptable value of 1.0×10^{11} Ohms. All other insulation resistance tests performed on Channel N35 were above the minimum acceptable values.

   Engineering evaluated the data and determined the value of 6.33×10^{10} Ohms for Channel N35 was acceptable and did not require any corrective action. This value was acceptable because the channel signal cable center wire to inner shield insulation resistance is above the end of detector life minimum acceptable value of 1.0×10^{9} Ohms and the amount of decrease in the insulation resistance is less than 0.5 decade. Intermediate Range Channel N35 was determined to be fully functional and capable of performing its design function.

2. In November 2012, cable testing was performed for the Unit 2 power range Channel N44 field cables. Out of tolerance readings for signal cable resistance and high voltage cable resistance were observed. The field cables for power range Channel N44 were disconnected and the field cables from the control room to the detector center wire to inner shield were measured. The detector cables measured resistances were acceptable.

   Prior to disconnection of the field cables at power range Channel N44 junction box, it was observed the mated connector pairs did not have heat shrink tubing or tape over the connectors and the connectors were immersed in water. The water was determined to be the result of a cavity seal leak. The connectors were cleaned and dried and reconnected to the detector. The insulation resistances were measured and the results were worse than the initial readings.

   Based on these readings, power range Channel N44 was replaced with a warehouse spare. The new power range Channel N44 detector was installed and the field cables were connected with heat shrink tubing installed and shrunk over the mated connector pairs. The insulation resistance for all three cables with the detector connected was measured from the control room and all insulation resistances exceeded the minimum value of 9.0×10^{9} Ohms. The upper detector signal cable insulation resistance was 4.4×10^{10} Ohms, the lower detector signal cable insulation resistance was 4.23×10^{10} Ohms, and the high voltage cable insulation resistance was measured at 2.43×10^{11} Ohms. An evaluation indicated the measured center wire to inner shield low insulation resistance on the upper detector current signal was the reason for the degraded condition for power range Channel N44. As a separate corrective action, the field cables for all three NI power range detectors were inspected to confirm there was no wetted cabling and that heat shrink tubing or tape was present on the connectors.

3. In October 2013, during the performance of I&C test procedures, the insulation resistance for the Channel N32 detector cable outer shield to ground was found to be below the administrative value of 1.0×10^8 Ohms.

   Based on the above findings, the test procedures were revised to include:

   - Technical references describing this issue and corrective actions
   - A new step and note statements to address the operability of the source and associated intermediate range detector and cabling when the measured resistance between the outer shield and ground of the detector cable is shorted or less than the minimum 1.0×10^8 Ohms administrative limit

     The above procedure revisions clarify that the outer shield is not credited in any manufacturer's design criteria, specifications, safety analysis, or licensing commitments. A grounded shield will not prevent the detectors from performing their intended function, and they can be declared “fully qualified” with respect to an operability determination. Should the resistance data be found to be below the minimum value as stated in the procedure during the performance of the test procedure, the System Engineer will be contacted to evaluate and resolve the issue

4. In December 2015, an effectiveness review of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The Non-Environmental Qualification (EQ) Cable Monitoring AMA includes elements of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

No gaps were identified by the effectiveness review associated with the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38). Results of the December 2015 effectiveness review for the other two associated aging management programs are provided in the SLRA sections indicated above.

5. In January 2016, a spike was received on the Unit 2 power range Channel N41 causing three annunciators to alarm. Channel N41 was declared inoperable, and flux maps were performed every twelve hours due to entering Technical Specification 3.7-1. The plant computer system as well as the Control Room recorder indications showed the spiking on the lower detector while the upper detector remained stable. The cause of spiking was due to an intermittent high resistance center wire connection at the penetration outside containment for the power range lower detector current signal. There were no operational consequences as a result of this power range channel spiking. Power range Channel N41 lower detector current signal cable between the drawer and the penetration was swapped with the installed spare cable.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed on the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4). Information from the summary of that effectiveness review is provided below:

   The implementing procedure for this activity includes instructions for the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and *Electrical Insulation for Inaccessible*

Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B2.1.39). This effectiveness review summary applies to the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38).

The Non-Environmental Qualification (EQ) Cable Monitoring Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the AMA that were reviewed included the selection of components to be inspected or tested, the inspection and testing of the components, the evaluation of the inspection and testing results, repair/replacements of components as required, and AMA document updates. Engineering reports from the 2004 to 2006 and 2014 to 2016 testing results of the sensitive, high-voltage, low-signal NI source, intermediate and power range cables were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken were consistent with the observed condition. The review also encompassed pertinent issues for age related degradation of cables and connections found in the Corrective Action Program from 2006 through 2017 for those components within the scope of license renewal.

Procedures that test the Nuclear Instrumentation cables have been enhanced as required by the corrective actions to add frequency requirements.

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 the aging effect of 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, 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 Used in Instrumentation Circuits* 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.

B2.1.39 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 the aging effect of reduced electrical insulation resistance of inaccessible medium-voltage cables (operating voltages of 2kV to 35kV) exposed to significant moisture.

The program applies to inaccessible or underground non-EQ medium-voltage power cable installations (e.g., installed in buried conduits, duct banks, underground vaults, manholes, cable trenches or direct buried installations), 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. Power cable exposure to significant moisture may cause reduced electrical insulation resistance that can potentially lead to failure of the cable's insulation system.

Periodic actions are taken to prevent non-EQ inaccessible medium-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manhole/vaults associated with cables included in this program are inspected for water collection 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/vaults and cable support structures are intact and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal is performed based on actual plant experience over time with an inspection frequency being at least annually and 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.

In-scope non-EQ inaccessible medium-voltage power cables routed through manholes, and duct banks are tested to detect reduced electrical insulation resistance 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.

There are no submarine cables or other cables designed for continuous wetting or submergence currently in the scope of this program. Future installed cables of this design would be considered for inclusion in this program.

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.

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):

Preventive Actions (Element 2)

1. Procedures will be revised to require inspection of in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly.

Parameters Monitored/Inspected (Element 3)

3. A procedure will be created for testing medium-voltage cable that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation.
4. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection.

Detection of Aging Effects (Element 4)

5. A new recurring event and maintenance schedule will be created for testing the “A” RSST cables at least once every six years.
6. A new recurring event and maintenance schedule will be created for testing the “B” RSST cables at least once every six years.
7. A new recurring event and maintenance schedule will be created for testing the “C” RSST cables at least once every six years.

8. A new procedure will be created for testing medium-voltage cable that includes a requirement that the specific type of test performed will be a proven test, utilizing one or more tests 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, for detecting deterioration of the insulation system due to submergence (e.g., selected test is applicable to the specific cable construction: shielded and non-shielded, and the insulation material under test).

Monitoring and Trending (Element 5)

9. A new procedure will be created for testing medium-voltage cable that includes a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation.

Acceptance Criteria (Element 6)

10. A new procedure will be created for testing medium-voltage cable that includes acceptance criteria for tests and inspections.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2009, following rain, water was observed draining out of the AAC cabling lead box located outside the condensate polishing building. A walkdown of the installation and a review of drawings was performed. An inspection of the ductlines entering the lead box discovered water in the ductlines. The ductlines were dewatered. Additionally, the individual ductlines were sealed, and the 4kV cables from the AAC diesel generator were entered into the cable life cycle management plan for testing. No wetting/degradation has been observed in recent inspections.

2. In September 2012, during an NRC review of License Renewal (LR) commitments and activities, the NRC LR review team identified that the proposed method to perform an annual visual inspection for water accumulation in an in-scope manhole may not be effective.

   The ‘C’ RSST power cable was re-routed to this manhole in April 2009. This was the only medium-voltage cable within the scope of initial license renewal.

It was identified that the manhole was not being periodically inspected for water accumulation. As a result, the inspection procedure was revised to add the in-scope manhole. Additionally, it was noted that the procedure did not allow for manhole entry to attempt a visual inspection of this 42 foot deep manhole.

It was determined that the use of a boroscope would be effective to provide for the necessary inspection. The procedure was revised accordingly.

3. In December 2015, an effectiveness review of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The Non-Environmental Qualification (EQ) Cable Monitoring AMA includes elements of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

   During this effectiveness review, timeliness of corrective action for sealing duct bank entrances for the underground ‘C’ RSST cables was identified. A Work Order that was created in 2011 to seal the duct bank entrances in order to prevent water and silt entry into a license renewal manhole had not been completed and there was no evaluation to allow delay of the work. Subsequently, an assessment was completed to evaluate whether any license renewal commitments were compromised by delay in implementing the work order. Annual visual inspections of the same license renewal manhole between 2013 and 2017 have found water level being controlled below the level of the cables such that the cables are not exposed to significant moisture, indicating that water in-leakage has not exceeded the capability of the sump pumps. No license renewal commitments were judged to be compromised and it was recommended that this work order be processed in accordance with station work management practices for implementation.

   Results of the December 2015 effectiveness review for the other two associated aging management programs are provided in the SLRA sections indicated above.

4. In September 2016, the periodic surveillances of an in-scope manhole for water intrusion were reviewed. Since March 2012, when the inspection procedure was established, there has been no excessive water in the manhole, and no long term wetting of the medium-voltage cables in this manhole.

   The in-scope medium-voltage cables have been tested with the following results:

   - In 2011, the SBO AAC diesel cables were tan-delta tested with satisfactory results. These cables have been entered into the medium-voltage testing program.
   - In 2012, the RSST feeder cables were tan-delta tested with satisfactory results.
   - In 2015, the EDG #1 cables were meggered and PI tested (non-shielded cable) with satisfactory results. They again were tested satisfactorily in 2017.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In November 2017, as part of oversight review activities, the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

7. In January 2018, an aging management program effectiveness review was performed of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4). Information from the summary of that effectiveness review is provided below:

   The implementing procedure for this activity includes instructions for the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39). This effectiveness review summary applies to the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

The Non-Environmental Qualification (EQ) Cable Monitoring Activity is meeting or exceeding the requirements of selected NEI 14-12, “Aging Management Program Effectiveness,” elements. Key activities of the AMA that were reviewed included the selection of components to be inspected or tested, the inspection and testing of the components, the evaluation of the inspection and testing results, repair/replacements of components as required, and AMA document updates. Engineering reports from the 2004/2006 and 2014/2016 inspection results of manholes containing in-scope medium-voltage cables were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed condition, such as raising cables from the bottom of the manhole when they were lying in water. The review also encompassed pertinent issues found in the Corrective Action Program from 2006 through 2017 for manhole water intrusion for those components within the scope of license renewal.

Due to the review of corrective actions to address wetted or submerged medium-voltage cables, the implementing procedure was enhanced to ensure manhole visual inspections are conducted at least annually and ensure the use of boroscopes to verify cables within the scope of license renewal were not exposed to submerged conditions when manholes cannot be entered.

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 and visual inspections of manholes to identify the aging effect of reduced electrical insulation resistance for non-EQ inaccessible medium-voltage 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, 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.

B2.1.40 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 the aging effect of reduced electrical insulation resistance leading to electrical failure of in-scope non-EQ inaccessible instrument and control (I&C) cables. This program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, manholes, or direct buried) non-EQ instrument and control cable, within the scope of subsequent license renewal that are 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. I&C cable exposure to significant moisture may cause reduced insulation resistance that can potentially lead to failure of the cable's insulation system. 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 I&C cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible I&C cables will be inspected to confirm that cables are not wetted or submerged in water, cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal will be performed based on actual plant experience over time with inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms will be inspected and their operation verified periodically.

In-scope, non-EQ, inaccessible I&C cables routed through manholes, pits, and duct banks that are 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 cable 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.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 2008, during the monthly manhole inspection, safety-related cables were found submerged in water in a license renewal manhole. Engineering issued a design change and sump pumps were installed in 2009 in two license renewal manholes to provide automatic water level control in the manholes. These sump pumps have been effective in preventing cables from being submerged. The eight most recent performances through 2017 of the manhole inspection procedure have found either no water or insufficient water in these two manholes to require pumping.

2. In October 2012, the NRC asked whether a cover on a license renewal manhole should have a gasket or sealant. Engineering determined that one of the two covers for the manhole should have a gasket or sealant installed. The manhole drawing was revised to include a detailed inset showing a neoprene o-ring to seal the manhole. A new gasket (o-ring) was installed on the cover for the manhole.

3. In January 2013, the NRC resident inspector entered a safety-related manhole, found water pooled in an area not visible from the top of the manhole, and three safety-related cables submerged in the water. Previous inspections, conducted in accordance with existing procedures, did not identify the submerged cables because the procedure requires the inspection to be performed from the ground level. Some time previously, the procedure had been revised, based upon OE from North Anna (the intent being to preclude entry into the manhole and prevent potential electrocution or other injury) to require inspections be performed from the ground level. The procedure regarding inspections of safety-related manholes was subsequently revised to include the use of a boroscope when performing the manhole inspections so that a more detailed inspection can be performed from outside of the manhole.

4. In May 2014, during the scheduled inspection of a license renewal manhole, cables were found in contact with an isolated wetted area on the floor. The as-found inspection revealed that the cables were not submerged in water and no accumulated water was found on the floor except for a very small puddle which was due to an uneven floor surface. However, the cable pit floor was found wet and cables were in contact with a wet floor. The cables were visually inspected and determined to be able to perform their intended function in their current condition.

The above examples of operating experience provide 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 activities for visual inspections to identify significant moisture and submergence to manage the aging effect of reduced insulation resistance for non-EQ inaccessible I&C 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 *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* 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.

B2.1.41 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 the aging effect of reduced electrical insulation resistance of inaccessible low-voltage power (operating voltage less than 2kV) cables exposed to significant moisture. This program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried) low-voltage power cables, within the scope of subsequent license renewal that are 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. Low-voltage power cable exposure to significant moisture may cause reduced insulation resistance that can potentially lead to failure of the cable's insulation system. 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 low-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible low-voltage power cables will be inspected to confirm that cables are not wetted or submerged in water, cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal will be performed based on actual plant experience over time with inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms will be inspected and their operation verified periodically.

In-scope, non-EQ, inaccessible low-voltage power cables routed through manholes, pits, and duct banks that are 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 points to 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 low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage or instrument and control 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 low-voltage power cables when testing is recommended. A sampling methodology will be used to evaluate a large number of low-voltage power cables 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.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 2008, during the monthly manhole inspection, safety-related cables were found submerged in water in a license renewal manhole. Engineering issued a design change and sump pumps were installed in 2009 in two license renewal manholes to provide automatic water level control in the relevant manholes. These sump pumps have been effective in preventing cables from being submerged. The eight most recent performances through 2017 of the manhole inspection procedure have found either no water or insufficient water in these two manholes to require pumping.

2. In July 2011, while dewatering ductline conduits for sealing, insulation damage was found on cables that perform intended functions in the AAC system. An engineering evaluation determined that the cable insulation had delaminated and swelled due to exposure to moisture. Further inspection in the cable trench identified other moist areas along the cable route where cable insulation damage was beginning. The cables were replaced in July 2011, and supports were placed under the cables to raise them up above the bottom of the trench in February 2016.
3. In October 2012, the NRC asked whether a manhole cover on a license renewal manhole should have a gasket or sealant. Engineering determined that one of the two covers for the manhole should have a gasket or sealant installed. The manhole drawing was revised to include a detailed inset showing a neoprene o-ring to seal the manhole. A new gasket (o-ring) was installed on the cover for the manhole.
4. In January 2013, the NRC resident inspector entered a safety-related manhole, found water pooled in an area not visible from the top of the manhole, and three safety-related cables submerged in the water. Previous inspections, conducted in accordance with existing procedures, did not identify the submerged cables because the procedure requires the inspection to be performed from the ground level. Some time previously, the procedure had been revised, based upon OE from North Anna Power Station (the intent being to preclude entry into the manhole and prevent potential electrocution or other injury) to require inspections be performed from the ground level. The procedure regarding inspections of safety-related manholes was subsequently revised to include the use of a boroscope when performing the manhole inspections so that a more detailed inspection can be performed from outside of the manhole.
5. In May 2014, during the scheduled inspection of a license renewal manhole, cables were found in contact with an isolated wetted area on the floor. The as-found inspection revealed that the cables were not submerged in water and no accumulated water was found on the floor except for a very small puddle which was due to an uneven floor surface. However, the cable pit floor was found wet and cables were in contact with a wet floor. The cables were visually inspected and determined to be able to perform their intended function in their current condition.

The above examples of operating experience provide 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 activities for visual inspections to identify significant moisture and submergence to manage the aging effect of reduced electrical insulation resistance for inaccessible low-voltage power cables within the scope of subsequent license renewal, 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.

B2.1.42 Metal-Enclosed Bus

Program Description

The *Metal Enclosed Bus* program is an existing condition monitoring program that manages the aging effect of degradation of electrical insulating material, reduced electrical insulation resistance, cracking, and loss of continuity or increased contact resistance of the bolted connections for metal enclosed bus (MEB) and internal components. Bus enclosure assemblies (internal and external), bus bar insulation, bus bar insulating supports, and bus bar bolted connections are included in the scope of the program.

The internal portions of the accessible bus enclosure assemblies are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The accessible bus insulation is visually inspected for signs of reduced insulation resistance, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination which may indicate overheating or aging degradation. The accessible internal bus insulating supports are visually inspected for structural integrity and signs of cracks. Accessible external metallic surfaces are visually inspected for unacceptable loss of material due to general, pitting, and crevice corrosion. Accessible enclosure assembly elastomers, including gaskets, boots, and sealants, are inspected for degradation, including surface cracking, crazing, scuffing, and changes in dimensions (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening and loss of strength. A sample of accessible bolted connections is inspected for increased electrical resistance of connection by measuring connection resistance using a micro-ohmmeter.

Metal enclosed buses are to be free from unacceptable visual indications of surface anomalies which suggest degradation exists. Additionally, unacceptable indications of external or internal material condition or contamination should not be present. An unacceptable indication is defined as a noted condition that, if left unmanaged, could lead to a loss of intended functions. External surfaces are to be free from general, pitting and crevice corrosion that result in unacceptable loss of material. Enclosure assembly elastomers are to be free from unacceptable visual indications of degradation. The bolted connections inspected by resistance measurements will be confirmed to be within the acceptance criteria established in program implementing procedures. Unacceptable results are subject to an evaluation under the Corrective Action Program.

The first inspection, including measuring connection resistance, is completed prior to the subsequent period of extended operation and at least every twelve years thereafter for emergency buses and every ten years thereafter for non-emergency buses, with the exception of MEB associated with transfer bus F. If internal inspections of metal enclosed bus associated with either transfer bus D or E identify degradation that would result in a loss of intended function, MEB associated with transfer bus F will be scheduled for inspection and testing. An opportunistic inspection of MEB associated with transfer bus F will also be performed if a dual unit outage of at least ten days duration occurs and transfer bus F can be deenergized without a significant safety impact to the units.

NUREG-2191 Consistency

The *Metal Enclosed Bus* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.E4, Metal Enclosed Bus.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4).

1. NUREG-2191 Element 4 notes that MEBs are generally accessible structures and as such are inspected and tested in their entirety. NUREG-2191 also notes that depending on particular plant configurations, some segments of the MEB may be considered inaccessible due to close proximity to other structures. In addition for inaccessible MEB internal or external segments, the applicant demonstrates that the inaccessible MEB segments evaluation, together with accessible MEB inspection and test program will continue to maintain the MEB consistent with the current licensing basis during the subsequent period of extended operation.

   MEB associated with transfer bus ‘F’ will be scheduled for inspection when aging degradation that impacts intended functions is confirmed during inspections of MEB associated with transfer bus D or E, or a dual unit outage of at least ten days duration occurs and transfer bus F can be deenergized without a significant safety impact to the units.

<u>Justification for Exception</u>

Transfer bus F provides power to Unit 1 emergency bus 1H and Unit 2 emergency bus 2J via MEB that is directly connected to the transfer bus without isolating circuit breakers. No alternate means are available to energize these two emergency buses from offsite power during performance of internal inspections of transfer bus F. As a result, deenergization of transfer bus F will cause each operating unit to load one of their emergency buses onto an EDG (1H bus loads onto EDG1 and the 2J bus loads onto EDG3), and enter a 7 day LCO. Even if one unit is in cold shutdown prior to initiating the bus inspection, the opposite unit will still have to load one emergency bus onto an EDG creating a significant safety impact. Therefore, to avoid a significant safety impact, deenergization of transfer bus F for inspection of its associated metal enclosed bus requires a dual unit outage.

Periodic internal inspections and testing of MEB associated with transfer buses D and E will be used to demonstrate that MEB associated with transfer bus F continues to remain consistent with the current licensing basis during the subsequent period of extended operation. The 4,160 V MEB associated with transfer buses D, E, and F are of identical materials and similar loading, and operate in an air-indoor uncontrolled environment that is air conditioned to limit maximum temperature. Internal inspections of sections of MEB associated with Transfer Buses D and E in 2010 and 2011 revealed no foreign material (i.e. dirt, dust buildup, or water intrusion), insulation degradation, or unacceptable resistance readings of bolted connections. In addition, if internal inspections identify degradation that would result in a loss of intended function, MEB associated with transfer bus F will be scheduled for inspection and testing. An opportunistic inspection of MEB associated with transfer bus F will also be performed if a dual unit outage of at least ten days duration occurs and transfer bus F can be deenergized without a significant safety impact to the units.

Detection of Aging Effects (Element 4)

2. NUREG-2191 Element 4 notes that the first inspection for measuring connection resistance is completed prior to the subsequent period of extended operation and every ten years thereafter. A 12-year inspection interval is requested for in-scope MEBs associated with emergency buses that are provided by the same manufacturer, in non-aggressive environments with similar operating characteristics.

   The first inspection for measuring connection resistance is completed prior to the subsequent period of extended operation and every 12 years thereafter instead of every ten years thereafter.

<u>Justification for Exception</u>

The four in-scope emergency bus MEBs are supplied by the same manufacturer under the same purchase order and use similar materials. Each of the four emergency bus MEBs is located in an air-indoor controlled environment and is normally energized. Loading is similar for each of the MEBs. The switchgear bus maintenance schedule for emergency buses is aligned with the EPRI Preventive Maintenance Basis template so that cubicle and bus inspections occur on a 12-year cycle. MEBs associated with emergency buses are inspected when the associated bus is scheduled for inspection. These inspections occur during refueling outages and are staggered to correspond with equipment maintenance windows. Consequently, emergency bus MEB inspections are staggered and will occur over a period of years during the 12-year inspection cycle. As a result, although each emergency bus MEB is inspected once every 12 years, at least one of the emergency bus MEBs provided by the same manufacturer, in non-aggressive environments with similar operating characteristics is inspected at a frequency of at least every six years during the 12-year period. If degradation is occurring, it can be identified earlier by the six year inspection frequency and additional corrective actions performed on the remaining emergency bus MEB inspection population, consistent with the degradation observed.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Inspection procedures similar in scope and content to the procedures used to inspect other metal enclosed bus within scope of subsequent license renewal will be developed for the in-scope metal enclosed bus (MEB) associated with the 1A2 480V bus.

Parameters Monitored/Inspected (Element 3)

2. For inaccessible MEB internal or external segments, procedures will be revised to require initiation of a condition report that will result in an engineering evaluation of the inaccessible MEB segments that, together with the accessible MEB inspection and test program, will continue to maintain the MEB consistent with the current licensing basis during the subsequent period of extended operation.

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

3. Procedures will be revised to require inspection of accessible internal portions (bus enclosure assemblies) of MEBs for cracks, corrosion, and foreign debris. Accessible bus electrical insulation material will be inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, discoloration, or swelling, indicating overheating or aging degradation. Accessible internal bus insulating supports will be inspected for structural integrity and signs of cracks. Accessible gaskets, boots, and sealants will be inspected for elastomer degradation including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength that could permit water or foreign debris to enter the bus.

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)

4. Procedure revisions will include a requirement for a sample of accessible bolted connections not covered with heat shrink tape or boots to be inspected for loose or corroded bolted connections and damaged hardware including cracked or split washers.

Detection of Aging Effects (Element 4)

5. Inspection procedures will be revised to add a note stating that 20% of the accessible bolted connection population, with a maximum of 25, is a representative sample.

6. A new recurring event and maintenance schedule will be created to inspect MEB associated with the 0-AAC-SW-0L bus on a maximum ten-year frequency. The first occurrence will be scheduled prior to the subsequent period of operation.
7. A new recurring event and maintenance schedule will be created to inspect MEB associated with the 1-EP-LCC-1A2 bus on a maximum ten-year frequency. The first occurrence will be scheduled prior to the subsequent period of operation.

Monitoring and Trending (Element 5)

8. Procedures will be revised to trend bus connection resistance values to provide information on the rate of connection degradation.

Acceptance Criteria (Element 6)

9. Accessible electrical insulation materials will be verified free from regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, and swelling. Accessible MEB internal surfaces will be verified to show no indications of corrosion, cracks, and foreign debris. Accessible elastomers (e.g., gaskets, boots, and sealants) will be verified to show no indications of surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength.

Corrective Actions (Element 7)

10. Procedures will be revised to specify that when any acceptance criterion is not met, the unacceptable results are entered into the Corrective Action Program

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Metal Enclosed Bus* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2009, an external inspection of the non-segregated phase bus duct, as an immediate response to the Columbia Generating Station event that identified bus duct maintenance practices as a potential contributor to a major station event, showed the bus to be in good condition with covers securely fastened and no evidence of current or past adverse environmental factors such as leaks or moisture intrusion. Non-segregated phase bus duct within the scope of subsequent license renewal is located within either a mild, air-indoor controlled environment or an air-indoor uncontrolled environment that is air conditioned to limit maximum temperature and is not installed outdoors nor exposed to salt, corrosive elements, high radiation, spray, or steam.

2. In Fall 2010, during the Unit 1 refueling outage, one of six sections of non-segregated phase bus duct associated with Transfer Bus D was opened and inspected in accordance with new procedural guidance added to the D Transfer Bus maintenance procedure in response to the Columbia event. The bus section was found to be clean and no issues were identified. Bolted connection resistances were within the guidance provided in the procedure.
3. In Spring 2011, during the Unit 2 refueling outage, two of six sections of non-segregated phase bus duct associated with Transfer Bus E were opened and inspected in accordance with new procedural guidance added to the E Transfer Bus maintenance procedure in response to the Columbia event. The bus sections were found to be clean and no issues were identified. Bolted connection resistances in one of the sections were within the guidance provided in the procedure. The bolted connections in the second section were insulated with tape and were visually inspected instead of taking resistance measurements. No issues were identified during this inspection.
4. In October 2014, a review of MEB inspection procedures was performed in response to an industry event resulting in failure of station equipment potentially caused by poor work practices associated with bus bar bolted connections in bus duct. The review identified that procedures did not exist for MEB associated with the 0L bus connections to the D and E transfer bus and stub bus connections for the emergency buses. Also, the procedure under development for MEB associated with the F transfer bus had not been issued. These procedures were subsequently issued in 2015 and 2016 for use and inspections scheduled as a recurring event in the Work Management System.

The above examples of operating experience provide objective evidence that the *Metal Enclosed Bus* program includes activities to perform visual inspections and electrical testing to identify reduced insulation resistance, cracking, and loss of continuity or increased contact resistance for MEB within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Metal Enclosed Bus* 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 *Metal Enclosed Bus* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Metal Enclosed Bus* 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.

B2.1.43 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 the aging effect of increased electrical resistance of electrical cable connections (metallic parts).

This program will perform a one-time inspection, 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: application (medium and low voltage), circuit loading (high load), connection type, 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.

Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting components under test 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 are to 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 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 examples of operating experience provide 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 SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. A search for plant-specific OE related to loose connections from January 2006 to March 2018 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.
2. In February 2011, while investigating an erratic standpipe indication on a recorder, a loose wire connection was found on the signal conditioner. Touching the wire caused erratic swings in the standpipe level indication. The terminal screw was tightened and no erratic indication was observed. It was not conclusive that the loosening of the terminal screw was due to the aging mechanisms of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation.
3. In May 2017, while performing logic testing in the AMSAC cabinet, a jumper wire was found broken from its lug on a terminal board. This wire is disconnected and tagged during the logic test procedure. An inspection of the lug showed it broke at the transition from the lug barrel to the lug tang due to having been cold worked due to the other end being repeatedly lifted for logic testing over the years. There were no prior issues identified related to this jumper being degraded. The lug was repaired and the lead re-landed. It was concluded that the broken lug was not due to the aging mechanisms of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation.

The above examples of operating experience provide 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 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 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.

B2.1.44 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 high-voltage insulators that are credited for recovery of offsite power.

The recovery path for loss of offsite power operates at 34.5 kV and 4,160 V (medium-voltage). Post and suspension insulators that are within the scope of subsequent license renewal operate at medium-voltage instead of high-voltage. There are, by definition, no high-voltage insulators within scope of subsequent license renewal. However, because of the similarities in materials and construction, medium-voltage insulators used in the recovery path for loss of offsite power will be included in the *High-Voltage Insulators* program.

High-voltage insulator surfaces will be visually inspected to detect reduced electrical insulation resistance aging effects including cracks, foreign debris, excessive salt, dust, fog, and industrial effluent contamination. Metallic parts of the insulator will be visually inspected to detect loss of material due to mechanical wear or corrosion.

The high-voltage 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. For high-voltage insulators that are coated, the visual inspection will be performed at least once every five years.

The first inspections 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 exception, to NUREG-2191, Section XI.E7, High-Voltage Insulators.

Exception Summary

The following program element(s) are affected:

Scope of Program (Element 1)

1. NUREG-2191, Element 1, identifies the insulators within the scope of this program as high-voltage insulators. ANSI C84.1-1989, American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60 Hertz), defines the High-Voltage class at a nominal system voltage of 115 kV to 230 kV. The Medium-Voltage class includes systems operating at nominal voltages of 34.5 kV and 4160 V.

High-voltage insulators within the scope of subsequent license renewal are those credited for recovery of offsite power consistent with 10 CFR 50.63 requirements for station blackout. These circuits are the 34.5 kV feeds from Buses 5, 6, and 7 in the switchyard to the reserve station service transformers (RSSTs) and the 4,160 V feeds from the RSSTs to Transfer Buses D, E, and F. The in-scope insulators operate at nominal voltages of 34.5 kV and 4160 V. Therefore, there are no devices that meet the definition of high-voltage insulators.

Justification for Exception

The 34.5 kV and 4160 V insulators credited for recovery of offsite power are similar in design and application to high-voltage insulators operating at 115 kV to 230 kV. Additionally, these insulators are constructed of similar materials and are susceptible to similar aging effects as high-voltage insulators. Therefore, the insulators credited for recovery of offsite power will be included under the *High-Voltage Insulators* aging management program.

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide 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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. The *High-Voltage Insulators* program is a new program. The following industry operating experience supports the basis for this program. Plant-specific operating experience was reviewed to ensure that the aging effects discussed in NUREG-2191, Section XI, XI.E7, aging management program are bounding (i.e., that there are no relevant plant-specific aging effects in addition to that described in NUREG-2191). The Dominion corrective action system was searched to determine if aging degradation has been identified for in-scope high-voltage insulators. No occurrences of excessive contamination or wear were identified.
2. In January 1989, Columbia Generating Station Unit 2 experienced a reactor shutdown due to flashover of a 500 kV insulator. The buildup of contamination (mineral deposits from cooling tower spray) was not removed by natural means (insufficient season rainfall) or by manual cleaning. A wind driven cooling tower plume engulfed the affected transformers and caused the flashover. Surry Power Station does not use cooling towers. The environment at SPS is not as arid as Columbia experiences and does not as readily promote deposition of contaminants on porcelain medium-voltage insulators. In addition, seasonal rainfall at SPS is significantly higher aiding in the normal rinsing of contaminants from the medium-voltage insulators. No flashover events for in-scope medium-voltage insulators have been identified at SPS.

3. In October 2012, Diablo Canyon Power Plant Unit 2 experienced a reactor shutdown following a flashover on a 500 kV capacitive coupled voltage transformer (CCVT) insulator. The heavy level of contamination from the salt spray environment was not properly considered during design of the CCVT that flashed over. Medium-voltage insulators at SPS have not experienced significant contamination from salt spray and seasonal rainfall is sufficient to minimize accumulation of contamination. No flashover events for in-scope medium-voltage insulators have been identified.

The above examples of operating experience provide objective evidence that the *High-Voltage Insulators* program will include activities to perform visual inspections to identify loss of material and reduced electrical 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 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 *High-Voltage Insulators* 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 *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 preventive 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.

This aging management program (AMP) provides an acceptable basis for managing structures and components (SCs) that are the subject of fatigue or cycle-based time-limited aging analyses (TLAAs) or other analyses that assess fatigue or cyclical loading, in accordance with the requirements in 10 CFR 54.21(c)(1)(iii). Examples of cycle based fatigue analyses for which this AMP may be used include, but are not limited to: (a) cumulative usage factor (CUF) analyses or their equivalent (e.g., I_t-based fatigue analyses, as defined in specific design codes) that are performed in accordance with ASME Code requirements for specific mechanical or structural components; (b) fatigue analysis calculations for assessing environmentally-assisted fatigue; (c) implicit fatigue analyses, as defined in the United States of America Standards (USAS) B31.1 design code or ASME Code, Section III rules for Class 2 and Class 3 components; (d) fatigue flaw growth analyses that are based on cyclical loading assumptions; (e) fracture mechanics analyses that are based on cycle-based loading assumptions; and (f) fatigue waiver or exemption analyses that are based on cycle-based loading assumptions.

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

The program verifies the continued acceptability of existing analyses through cycle counting. The program assures that the number of occurrences of each critical transient remains within the limits of the fatigue analyses, which in turn ensure that the analyses remain valid. For the pressurizer, the program documents the severity of operational parameters. Stress-based fatigue monitoring or other similar updates to evaluations of the fatigue analyses are not used to ensure the design or analysis-specific limit continues to be met.

CUF_{en} is CUF adjusted to account for the effects of the reactor water environment on component fatigue life. For a plant, the effects of reactor water environment on fatigue are evaluated by assessing a set of sample critical components for the plant. Examples of critical components are identified in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components;” however, plant-specific component locations in the reactor coolant pressure boundary may be more limiting than those considered in NUREG/CR-6260, and thus should also be considered. Environmental effects on fatigue for these critical components may be evaluated using the guidance in Regulatory Guide (RG) 1.207, Revision 1, “Guidelines for Evaluating the Effects of Light Water Reactor Coolant Environments in Fatigue Analyses of Metal Components;” alternatively, the bases in NUREG/CR-6909, Revision 0, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials,” (with “average temperature” used consistent with the clarification that was added to NUREG/CR-6909, Revision 1); or other subsequent U.S. Nuclear Regulatory Commission (NRC)-endorsed alternatives.

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).

The program monitors and tracks the number of occurrences of each of the critical thermal and pressure transients for the ASME Code, Section III, sentinel locations in order to maintain the CUF_{en} below the design limit of 1.0. For the pressurizer and pressurizer surge line, the program documents the severity of operational parameters.

For reactor coolant system branch line piping connections subject to environmentally assisted fatigue, the program manages the effects of aging due to fatigue through the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) by conducting inspections in accordance with ASME Code, Section XI, Non-mandatory Appendix L.

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

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

When a flaw is identified in an ASME Class 1 Vessel by inservice inspection, ASME Code, Section XI, Non-mandatory Appendices A and C provide guidance on the performance of fatigue flaw crack growth evaluations to determine acceptability for continued service of reactor coolant system pressure boundary components subjected to cyclic loadings. In such a case, the predicted size of an identified flaw is a computed parameter suitable for determining the appropriate inspection frequency through a fatigue crack growth evaluation. The program monitors and tracks the number of occurrences of each of the critical thermal and pressure transients for the selected components that are used in the crack growth evaluations to verify that the inspection frequencies remain appropriate.

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 enhancement(s) will be implemented in the following program elements):

Parameters Monitored/Inspected (Element 3)

1. The program cycle counting procedures will be revised to add the “Normal Charging and Letdown Shutdown and Return to Service” transient cycle associated with the ASME Code, Section XI, Appendix L analysis.

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)

2. Procedures will be revised to require monitoring and tracking of transient cycles associated with the ASME Code, Section XI, Appendix L analysis be performed between the inspections for each ASME Code, Section XI, Appendix L location. Consistent with existing program cycle counting, a surveillance limit will be established to initiate corrective action prior to exceeding transient cycle assumptions in the ASME Code, Section XI, Appendix L analysis.

Corrective Actions (Element 7)

3. Procedures will be revised to expand existing corrective action guidance associated with exceeding a cycle counting surveillance limit to recommend consideration of component repair, component replacement, performance of a more rigorous analysis, performance of an ASME Code, Section XI, Appendix L flaw tolerance analysis, or scope expansion to consider other locations with the highest expected U_{en} values.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2011, a tornado passing through the SPS switchyard resulted in a loss of offsite power and the ensuing reactor trip on both units. During the Technical Specification 3.0.1 required post-trip reactor coolant system cooldown, the pressurizer spray line delta-T on both units exceeded the 320°F limit allowed by Technical Specification 3.1.B.3. The Unit 1 pressurizer temperature was 425°F with the regenerative heat exchanger charging outlet temperature at 103°F, resulting in a spray line delta-T of 322°F on Unit 1. The Unit 2 pressurizer liquid temperature was 438°F with the regenerative heat exchanger charging outlet temperature at 110°F, resulting in a spray line delta-T of 328°F on Unit 2. At the time of delta-T exceedance, pressurizer spray was being provided by auxiliary spray from the charging pump discharge, since only one reactor coolant pump was in-service at that time and unable to provide adequate spray flow. The lowest temperature noted for auxiliary spray on Unit 1 was 94°F, and 105°F on Unit 2. In response to the high pressurizer spray line delta-T, operators attempted to increase spray line temperature by securing proportional heaters and using only the ‘A’ spray valve for pressure control. No spray line temperature increase was noted, and the ‘A’ spray valve was ineffective in controlling reactor coolant system pressure. In response, the proportional heaters were re-energized and auxiliary spray was used for reactor coolant system pressure control. Eventually, reactor coolant system pressure control was established by securing all pressurizer heaters, fully opening ‘A’ spray valve, and cycling pressurizer heaters as necessary.

Following the event, corrective action was assigned to Engineering to evaluate the temperature excursion impact to the reactor coolant system and initiate actions as required. This was evaluated and determined to be within the bounds of the inadvertent initiation of auxiliary spray event analyzed in the Westinghouse Pressurizer Equipment Specification. This event was the third of ten allowed for each unit. The Unit 1 and Unit 2 reactor coolant system Transient Logs were updated to reflect this event.

The above examples of operating experience provide objective evidence that the *Fatigue Monitoring* program includes activities to perform volumetric and visual inspections to identify and manage cycle-based 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 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 a loss of intended function.

Conclusion

The continued implementation of the *Fatigue Monitoring* 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.

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 x 10^{17} n/cm^2 (E>1MeV) during the subsequent period of extended operation to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analysis will remain within their applicable limits.

The program includes provisions to calculate and evaluate reactor vessel (RV) neutron fluence projections for the RV beltline and extended beltline; withdraw and test reactor in-vessel material surveillance capsules, dosimeters, and thermal monitors; use the calculated fluence projections as inputs to perform pressurized thermal shock assessments in accordance with 10 CFR 50.61; calculate reactor coolant system Pressure/Temperature (P-T) Limit Curves in accordance with 10 CFR 50, Appendix G; assess upper shelf energy in accordance with 10 CFR 50 Appendix G; track EFPY and calculate setpoints for the Low Temperature Overpressure Protection System.

The methods and assumptions for determining RV 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 RV 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-18028-NP, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 & 2.” In the plant-specific WCAP, the use of RG 1.190-adherent methods to estimate neutron fluence for the extended beltline regions was justified due to 1) the close proximity (regions approximately 1 ft below and 4 ft above) of the RV beltline region immediately surrounding the reactor core, and 2) the SPS-specific neutron fluence calculations for the RV beltline materials agree with the fluence measurements from the tested surveillance capsule dosimetry. The methods used to identify the fluence for the materials within the extended beltline region are consistent with RG 1.190. While the fluence projections for the inlet and outlet nozzles may have greater uncertainty than other beltline materials, these fluence projections are acceptable for performing RV integrity assessments for the subsequent license renewal period. The basis for this determination is discussed in Section 4.2.1, Neutron Fluence Projections.

For reactor vessel internals (RVI), the EPRI 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), during the development of reactor vessel internals aging management guidance. A gap analysis evaluated the impact of, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," MRP-227-A, inspection recommendations for the subsequent period of extended operation. Ongoing inspection of RVI components for the above radiation damage mechanisms is performed in accordance with *PWR Vessel Internals* program (B2.1.7) and neutron fluence monitoring for the RVI is not required.

There are sufficient surveillance capsules remaining in-vessel to evaluate the subsequent license renewal period of extended operation so that ex-vessel capsules are not required. The *Reactor Vessel Material Surveillance* program (B2.1.19), which includes neutron fluence monitoring, also includes provisions to review and update the program's design and licensing basis based on regulatory or industry changes, as well as internal calculation and testing results.

NUREG-2191 Consistency

The *Neutron Fluence Monitoring* program, as part of the *Reactor Vessel Material Surveillance* program, is an existing condition monitoring program and is consistent with NUREG-2191, Section X.M2, Neutron Fluence Monitoring.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Neutron Fluence Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Dominion is a member of the Babcock and Wilcox (B&W) Owner's Group Reactor Vessel Working Group (RVWG). SPS participates in the RVWG's Master Integrated Reactor Vessel Surveillance Program (MIRVSP). The MIRVSP integrates the plant specific reactor vessel surveillance programs of the participants, the existing supplemental B&W Owners Group irradiation capsules, and additional supplemental irradiation capsules to assure the availability of high fluence and thermal annealing data for the participants' reactor vessels. One objective of the MIRVSP is to maximize the effectiveness of data sharing among participants to assure that required data is available to the participants for current and extended plant operation.

2. In 2010, a licensee amendment request (LAR) (ADAMS Accession No. ML100320264) summarized the program impact reviews performed for a 1.6% measurement uncertainty recapture (MUR) power uprate (PU). In the Safety Evaluation Report (ADAMS Accession No. ML101750002), the NRC staff agreed with the following LAR conclusions:

   (i) The projected upper shelf energy (USE) values for this measurement uncertainty recapture (MUR) PU application were bounded by earlier analyses. The proposed MUR PU was therefore acceptable with respect to the P-T limits and USE.

   (ii) The Unit 1 and 2 RVs will remain within their limits for pressurized thermal shock (PTS) after the MUR PU and the RV materials would continue to meet the PTS screening criteria requirements of 10 CFR 50.61.

   (iii) Since the MUR PU resulted in very small changes to aging parameters such as temperature and neutron flux, the current aging management program for the reactor internals was acceptable.

3. In 1997, the Unit 1 Capsule X Withdrawal and Test Results report indicated that the specimens in Unit 1 Capsule X were exposed to fluences equivalent to approximately 16.1 effective full-power years (EFPY), 2.11×10^{19} neutrons/cm^2 based on the calculated fluence, and satisfy the upper-shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. The adjusted reference temperatures have been shown to be less than those used in the Unit 1 P-T limit curves, thereby demonstrating margin in the operating limits.

4. In 2002, the Unit 2 Capsule Y Withdrawal and Test Results report indicated that specimens in Unit 2 Capsule Y were exposed to fluences equivalent to approximately 20.3 EFPY, 2.72×10^{19} neutrons/cm^2 based on the calculated fluence, and satisfy the upper-shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. Adjusted reference temperatures were shown to be less than those used in the Unit 2 P-T limit curves, thereby demonstrating margin in the operating limits.

The above examples of operating experience provide objective evidence that the *Neutron Fluence Monitoring* program includes activities to calculate projected neutron fluence and measure actual neutron fluence values 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 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.

B3.3 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 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform 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 EQ program was evaluated against the Division of Operating Reactor (DOR) Guidelines, “Guidelines for Evaluation of Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors,” and the basis for equipment qualification is Inspection and Enforcement Bulletin (IEB) 79-01B (IEB 79-01B), “Environmental Qualification of Class 1E Equipment,” and IEEE Standard 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations,” as codified by 10 CFR 50.49. IEEE 323-1974 provides the criteria for safety-related equipment (electrical “Class 1E” equipment) and the basis for categorizing equipment important to safety, and defines environmental service conditions. Therefore, the EQ program includes and identifies electrical equipment important to safety and that could be exposed to harsh environment accident conditions, consistent with 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 life 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 (ALE) 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 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.

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 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 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, following enhancement, will be consistent with NUREG-2191, Section X.E1, Environmental Qualification of Electric Components.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. Existing procedures will be enhanced to include a requirement for plants that are entering or have entered their subsequent period of extended operation to perform a walkdown once prior to the subsequent period of extended operation and every ten years thereafter. Accessible electrical EQ equipment will be visually inspected and the EQ environment evaluated to identify in-scope electrical equipment subjected to an adverse localized environment (ALE). If an ALE is found, evaluation of the impact of the ALE on EQ electrical equipment, including qualified life, will be performed.

Corrective Actions (Element 7)

2. Existing procedures will be enhanced to evaluate and take appropriate corrective actions, which may include changes to qualified life, when an unexpected adverse localized environment or condition is identified during operational or maintenance activities that affect the qualification of electrical equipment.

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 their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2012, during a periodic check of Equipment Qualification Master List (EQML) replacement dates versus work orders completed for EQ components it was discovered that a solenoid operated valve (SOV) was not replaced at the end of its qualified life (14.5 years) as required by its Qualification Documentation Report (QDR). Ambient temperature data collected over a period of time indicated that there was excess conservatism in the equipment service conditions used in the original qualified life analysis. The SOV qualified life was reanalyzed by reducing some of the excess conservatism so that the qualified life was extended to 17 years. The SOV was subsequently replaced in November of 2012.

2. In March 2015, it was identified that four component cooling (CC) water resistance temperature detectors (RTDs) with Regulatory Guide 1.97 functions had been inappropriately removed from the EQ program in 1996. The qualified life evaluation for these four specific CC RTDs was inappropriately removed from the qualification documentation report when other CC RTDs that no longer performed Regulatory Guide 1.97 functions were removed from the EQ program. The qualified life of the four affected RTDs is 60 years, and review of the maintenance procedure for sealing the heads of these RTDs found that the procedure includes the EQ program requirements. The qualification documentation report was updated to restore the four CC RTDs so that they retained their Regulatory Guide 1.97 functions.
3. In September 2015, Steris-Isomedix issued a 10 CFR 50 Part 21 notification indicating that the radiation dose delivered to components may be approximately 9.6% lower than expected during the radiation aging portion of equipment qualification testing programs. EQ files were reviewed to identify affected components. No immediate concerns were identified with the qualified life of any affected components. The EQ files are being updated to reflect this approximately 9.6% reduction in radiation aging dose.
4. In October 2016, Dominion was notified by ATC that Validyne had used substitute integrated circuit chips and other subcomponents in the Validyne HD310 multiplexer for approximately 16 years without documenting that the substitute parts met the EQ criteria specified in Validyne test report QTR-82-002. The components were evaluated against EPRI NP-3326 which reported satisfactory testing of similar components subjected to higher radiation fields than those found for the Validyne locations. ATC will provide an addendum to QTR 82-002 with type testing to re-qualify the undocumented subcomponents. The EQ documentation will be updated when the addendum is received.
5. In November 2016, mechanical insulation was found to be incorrectly installed on two Unit 1 reactor coolant system RTDs. The insulation was repositioned to the correct location and the qualified life of the RTDs was evaluated to determine if they had been affected. Based on temperatures sampled at hot shutdown for similar RTDs on Unit 2, it was determined that the RTDs could be returned to full qualification and remain on their original replacement schedules.
6. In November 2016, during Nuclear Oversight (NOD) audit 16-11, it was determined that EQ work orders were not being reviewed once per quarter as required. The last review completed was for the first quarter 2016. Internal tracking items were created and work order reviews were performed for each quarter through the fourth quarter of 2017. Review assignments are now tracked by the performance improvement group at the station.

7. In February 2018, a Plant Improvement Report was issued to document a self-assessment of the EQ program at SPS and North Anna Power Station for programmatic and regulatory compliance, and for appropriate configuration management of the EQ program and EQ-related equipment. No cross-cutting programmatic elements were identified during the review and no areas for improvement were noted. A number of recommendations were developed for further technical and programmatic improvements.

The above examples of operating experience provide objective evidence that the *Environmental Qualification of Electric Equipment* program includes 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, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Environmental Qualification of Electric Equipment* 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.

Surry Power Station

Units 1 and 2

Application for Subsequent License Renewal

Appendix C
MRP-227-A Gap Analysis for PWR Vessel Internals Aging Management

Intentionally Blank

List of Tables

List of Figures

NONE

Intentionally Blank

APPENDIX C

C1 INTRODUCTION

The *PWR Vessel Internals* program (B2.1.7) is an existing condition monitoring program that manages cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of pre-load for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion cracking (IASCC), 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 (B2.1.7) is based on EPRI Technical Report No. 3002005349, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines,” (MRP-227, Revision 1), which is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, “Guideline for the Management of Materials Issues”. Certain input information for MRP-227, Revision 1 was obtained from MRP-175 and MRP-191. MRP-175 provides screening criteria for PWR internals materials for each age-related degradation mechanism considered: stress corrosion cracking, irradiation-assisted stress corrosion cracking, wear, fatigue, thermal aging embrittlement, irradiation embrittlement, void swelling, and thermal and irradiation-induced stress relaxation/irradiation creep. The screening criteria provide a basis to either screen in or screen out a component. MRP-191 summarizes the results of screening, categorizing, and ranking for Westinghouse-designed internals components based on susceptibility and significance for age-related degradation.

Per NUREG-2191 and NUREG-2192, MRP-227-A continues to provide the reference basis for the *PWR Vessel Internals* program (B2.1.7) during the subsequent period of operation to 80 years. The reference basis is supplemented with this gap analysis to determine changes required to provide reasonable assurance that aging effects will be managed. MRP-227, Revision 1, the results of the Westinghouse expert panel review summarized in Westinghouse letter LTR-AMLR-17-35, “Transmittal of Preliminary Results from the MRP-191 Expert Panel Review in Support of Subsequent License Renewal for Surry Units 1 and 2”, and MRP-2018-022, “Transmittal of MRP-191-SLR Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants” are the key input references for this gap analysis.

The *PWR Vessel Internals* program (B2.1.7) applies the guidance in MRP-227, Revision 1, for inspecting, evaluating, and, if applicable, dispositioning non-conforming RVI components at Units 1 and 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), and “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.

C2 APPLICABILITY REQUIREMENTS FOR SUBSEQUENT LICENSE RENEWAL

C2.1 BASES PROVIDED BY MRP 2018-022

Engineering analyses and evaluations for developing the updated *PWR Vessel Internals* program (B2.1.7) for SLR utilized several assumptions for the operation of the power plant, as described below. These assumptions have been validated for Surry Units 1 and 2.

(a) Each of the units has operated for 30 years or less with high-leakage core loading patterns (fresh fuel assemblies loaded in peripheral locations) followed by implementation of a low-leakage fuel management strategy for the remaining years of operation. The three limitations that define low-leakage operation for SLR considerations are the same as those used for the initial period of extended operation:

- Heat generation rate figure of merit: F ≤ 68 watts/cm^3
- Average core power density < 124 watts/cm^3
- Active fuel to fuel alignment pin distance > 12.2 inches

(b) The units have operated for the majority of their lifetimes as base-loaded units and are currently operating as base-loaded (each unit operates at fixed thermal power levels and does not usually vary power on a calendar or load demand schedule).

(c) The units have not implemented design changes beyond those identified in general industry guidance or recommended by the original vendors.

(d) The unit listings of functional components have been confirmed to include the components and material class as listed in the latest revision of MRP-191.

C2.2 KEY FACTORS IMPACTING THE DEVELOPMENT OF MRP-227 FOR SLR

MRP-227-A and MRP-227, Revision 1, were developed for the initial period of extended operation in order to extend the original operating license from 40 years to 60 years. Increasing plant operation time to 80 years could affect the content of the *PWR Vessel Internals* program (B2.1.7) because aging degradation mechanisms for reactor vessel internals components have had additional time to evolve, and because the neutron irradiation fluence for those components has continued to increase.

The eight aging degradation mechanisms that can have an impact on the reactor vessel internals were investigated in detail in MRP-175. The following mechanisms were included:

- Stress corrosion cracking (SCC) [SCC at a weld: SCC-W]
- Irradiation-assisted stress corrosion cracking (IASCC)
- Wear
- Fatigue
- Thermal embrittlement (TE)
- Irradiation embrittlement (IE)
- Void swelling
- Thermal and irradiation-induced stress relaxation or irradiation creep (ISR/IC)

SCC, IASCC, wear, fatigue, and thermal embrittlement are all time-dependent, increasing with additional time spent exposed to the environment. IASCC also has an impact from radiation dose accumulation, since it does not occur at zero or very low dose but does occur at higher doses. IE, ISR/IC, and VS are all dose-dependent, increasing with increased radiation exposure. Some of these effects, particularly IE and TE, typically reach a saturation level after enough dose exposure or time. Increasing the assumed operational time from 60 years to 80 years increases both time of exposure and the accumulated radiation dose. These two parameters were evaluated during the expert panel review for MRP-191.

MRP-175, Revision 1, provided updated screening threshold values for each of the eight aging degradation mechanisms with consideration of recent testing and operating experience, and the extension to 80 years of plant life. The previous MRP-175, Revision 0, screening thresholds were quite conservative and most did not include an impact for the length of time that the component was exposed. For example, SCC was based on the applied stress and the condition of the material and not the length of time that the component was exposed to the applied stress. Thus, only two degradation mechanisms required updates to their screening thresholds: IASCC and fatigue.

The threshold for IASCC required an update because of new laboratory data published since MRP-175, Revision 0 which resulted in a new trend curve for IASCC. The threshold for fatigue required an update due to a combination of additional time for operating to 80 years (i.e., additional fatigue cycles) and incorporation of environmental effects on fatigue, which together resulted in a lower cumulative usage factor (CUF) threshold of 0.036 for the fatigue threshold.

The new trend curve for IASCC in MRP-175, Revision 1 did not impact the screening because the screening criteria used in MRP-191, Revision 0 and Revision 1, were more conservative than the IASCC curve. The SLR expert panel review continued to use the same conservative IASCC screening criteria as MRP-191, Revision 0 and Revision 1. The lower CUF threshold did result in a significantly larger number of screened-in components; however, the expert panel determined that the lower screening criteria did not result in promotion of new lead components for fatigue.

Addressing increases in neutron irradiation dose at 80 years involved calculations specifically for representative Westinghouse-designed plants. To obtain representative dose projections with a reasonable amount of added conservatism, dose projections were generated using a model for a representative 3-loop plant at 72 EFPY. To account for variations in axial and radial power shapes, two different dose projections were generated:

- A flat axial power shape that produced conservative dose projection results above and below the active fuel, and
- A best-estimate and realistic axial power shape that produced dose projection results that were more limiting in the radial direction.

These two dose projections were overlaid and the higher dose at any point was utilized.

Table C2.2-1 provides a summary of parameter screening results for the *PWR Vessel Internals* components which require aging management. Applicable ranges are provided for CUF and maximum neutron fluence values.

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	1
		C-tubes (Note 3)	Austenitic SS	304 SS	No	No	Yes	Yes	No	No	3
		Guide tube enclosures (Note 3)	Austenitic SS	304 SS	No	Yes	No	Yes	No	No	3
		Flanges - intermediate (Note 3)	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
			Cast Austenitic SS	CF8	Yes	Yes	No	Yes	Yes	No	1
		Flanges - lower	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	4
			Cast Austenitic SS	CF8	Yes	Yes	No	Yes	Yes	No	4
		Flexureless inserts (Unit 2 only) (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Flexures (Unit 1 only) (Note 3)	PH Ni-base Alloy	X-750	Yes	No	No	Yes	No	Yes	1
		Guide plates (cards)	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	2
			Cast Austenitic SS	CF8	Yes	Yes	Yes	Yes	Yes	No	2
		Guide tube support pins	PH Ni-base Alloy	X-750 (U-1)	Yes	No	Yes	Yes	Yes	Yes	4
		Guide tube support pins (Note 3)	Austenitic SS	316 SS (U-2)	Yes	No	Yes	Yes	Yes	Yes	4
		Housing plates (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
			Cast Austenitic SS	CF8	No	No	No	No	No	No	1
		Inserts (Unit 1 only) (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
			Cast Austenitic SS	CF8	No	No	No	No	No	No	1
		Sheaths (Note 3)	Austenitic SS	304 SS	No	No	Yes	Yes	Yes	No	3

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Upper internals assembly (cont.)	Control rod guide tube assemblies and flow downcomers (cont'd)	Support pin nuts	Austenitic SS	Alloy 600 (U-1)	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
		Support pin nuts (Note 3)	Austenitic SS	316 SS (U-2)	No	No	No	Yes	No	No	4
	Mixing devices	Mixing devices (Note 3)	Cast Austenitic SS	CF8	No	Yes	No	Yes	No	No	4
	Upper core plate and fuel alignment pins	Fuel alignment pins	Austenitic SS	304 SS	Yes	No	Yes	Yes	No	No	4
		Upper core plate	Austenitic SS	304 SS	Yes	No	Yes	Yes	Yes	No	4
		Upper core plate insert (Note 3)	Austenitic SS	304 SS	No	No	Yes	No	N/A	No	3
		Upper core plate insert bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	N/A	Yes	3
		Upper core plate insert locking devices and dowel pins (Note 3)	Austenitic SS	304L SS (Note 2)	No	No	No	Yes	N/A	No	3
		Upper core plate insert locking devices and dowel pins (Note 3)	Austenitic SS	316 SS (Note 2)	No	No	No	Yes	N/A	No	3
	Upper instrumentation conduit and supports	Bolting (Note 3)	Austenitic SS	316 SS	No	No	No	No	No	Yes	1
			Austenitic SS	304 SS	No	No	No	No	No	Yes	1
		Brackets, clamps, terminal blocks, and conduit straps (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	3
			Cast Austenitic SS	CF8	No	No	No	Yes	No	No	3

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Upper internals assembly (cont.)	Upper instrumentation conduit and supports (cont'd)	Conduit seal assembly: body, tubesheets, tubesheet welds (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Conduit seal assembly: tubes (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	1
		Conduits (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	2
		Flange base (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Locking caps (Note 3)	Austenitic SS	304L SS	No	No	No	Yes	No	No	1
		Support tubes (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
	Upper support column assemblies	Adapters (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		Bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	No	Yes	4
		Column bases (Note 3)	Cast Austenitic SS	CF8	Yes	No	No	No	No	No	4
		Column bodies (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	2
		Extension tubes (Note 3)	Austenitic SS	304 SS	No	Yes	No	No	No	Yes	1
		Flanges (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		Lock keys (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	3
		Nuts (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
			Austenitic SS	302 SS	No	No	No	Yes	No	No	1
Upper internals assembly (cont.)	Upper support plate assembly – flat plate design	Upper support plate (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	1
		Upper support ring	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
		Deep beam ribs (Note 3)	Austenitic SS	304 SS	Yes	Yes	No	No	No	No	1
		Deep beam stiffeners (Note 3)	Austenitic SS	304 SS	No	Yes	No	No	No	No	1
		Bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	No	Yes	1
		Locking device (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	6
		Baffle-edge bolts	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	6
		Baffle plates	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	6
		Baffle-former bolts	Austenitic SS	347 SS	Yes	No	No	Yes	Yes	Yes	6
		Corner bolts	Austenitic SS	347 SS	Yes	No	No	Yes	N/A	Yes	6
		Barrel-former bolts	Austenitic SS	347 SS	Yes	No	No	Yes	Yes	Yes	5
		Former plates	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	6
	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
		BMI column bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	5
		BMI column collars (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	5
		BMI column cruciforms (Note 3)	Cast Austenitic SS	CF8	No	No	No	Yes	No	No	5
		BMI column extension bars (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	5
		BMI column extension tubes (Note 3)	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
		BMI column locking devices (Note 3)	Austenitic SS	304L SS	No	No	No	No	No	No	5
		BMI column nuts (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	Yes	5

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Lower internals assembly (cont.)	Core barrel	Core barrel flange	Austenitic SS	304 SS	No	Yes	Yes	Yes	No	No	1
		Core barrel outlet nozzles	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	1
		Lower core barrel axial welds, includes MAW and LAW	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	5
		Lower core barrel girth welds (includes LGW and LFW)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	5
		Upper core barrel axial welds (includes UAW)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	2
		Upper core barrel girth welds (includes UFW and UGW)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	2
	Diffuser plate	Diffuser plate (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	2
	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	Ni-base Alloy	Alloy 600	No	Yes	No	Yes	No	No	6
		Flux thimbles (tubes)	Ni-base Alloy	Alloy 600	No	Yes	Yes	Yes	No	No	6
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 3)	Austenitic SS	316 SS	No	No	No	No	No	No	1
		Irradiation specimen access plug (plug) (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		Irradiation specimen access plug (spring) (Note 3)	PH Ni-base Alloy	X-750	No	No	No	No	No	No	1
		Irradiation specimen guide (Note 3)	Austenitic SS	304 SS	No	No	Yes	Yes	No	No	2
	Lower core plate and fuel alignment pins	Fuel alignment pins	Austenitic SS	304 SS	Yes	No	Yes	No	No	No	6
		Lower core plate	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	5

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Lower internals assembly (cont.)	Lower support column assemblies	Lower support column bodies	Cast Austenitic SS	CF8	No	No	No	Yes	No	No	5
		Lower support column bolts	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	5
		Lower support column bolt locking devices (Note 3)	Austenitic SS	304L SS	No	No	No	Yes	N/A	No	5
		Lower support column nuts (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	Yes	5
		Lower support column sleeves (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	2
	Lower support forging	Lower support forging	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	1
	Neutron panels/ thermal shield	Thermal shield bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	2
		Thermal shield dowels (Note 3)	Austenitic SS	316 SS	No	No	No	Yes	No	No	2
			Austenitic SS	304 SS	No	No	No	Yes	No	No	2
		Thermal shield flexures	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	2
		Thermal shield flexure bolts (Note 3)	Austenitic SS	316 SS	No	No	No	Yes	N/A	Yes	2
		Thermal shield flexure locking devices and dowel pins (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	N/A	No	2
			Austenitic SS	304L SS	No	No	No	Yes	N/A	No	2
		Thermal shield (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	4
	Radial support keys	Radial support key bolts (Note 3)	Austenitic SS	316 SS	Yes	No	Yes	Yes	No	Yes	1
		Radial support key dowels (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	N/A	No	1
			Austenitic SS	316 SS	No	No	No	Yes	N/A	No	1
		Radial support key lock keys (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Radial support keys (Note 3)	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	No	No	1
		Radial support keys	Hard Facing Alloy	Stellite	No	No	No	Yes	No	No	1

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Lower internals assembly (cont.)	Secondary core support (SCS) assembly	SCS base plate (Note 3)	Austenitic SS	304 SS	No	Yes	No	Yes	No	No	1
		SCS bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	No	Yes	1
		SCS energy absorber (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		SCS guide post (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		SCS housing (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		SCS lock keys (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Upper and lower tie plates (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	Yes	Yes	1

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Interfacing components	Interfacing components	Clevis insert bolts	PH Ni-base Alloy	X-750	Yes	No	Yes	No	No	Yes	1
		Clevis insert dowels	Ni-base Alloy	Alloy 600	No	No	No	Yes	N/A	No	1
		Clevis insert locking devices (Note 3)	Ni-base Alloy	Alloy 600	No	No	No	Yes	No	No	1
		Clevis inserts (Note 3)	Ni-base Alloy	Alloy 600	Yes	No	Yes	Yes	No	No	1
		Clevis inserts	Hard Facing Alloy	Stellite	No	No	Yes	Yes	No	No	1
		Head and vessel alignment pin bolts (Note 3)	Austenitic SS	316 SS	No	No	No	Yes	No	Yes	1
		Head and vessel alignment pins (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	Yes	No	1
		Internals hold-down spring	Austenitic SS	304 SS	Yes	No	Yes	Yes	No	Yes	1
		Upper core plate alignment pins	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	3
			Hard Facing Alloy	Stellite	No	No	Yes	No	N/A	No	3
		Thermal sleeves	Austenitic SS	304 SS	No	No	Yes	No	N/A	No	1
		Thermal sleeve guide funnels (Note 3) Unit 2	Cast Austenitic SS	CF8	No	No	Yes	No	N/A	No	1
		Thermal sleeve guide funnels (Note 3) Unit 1	Austenitic SS	304 SS	No	No	Yes	No	N/A	No	1

a. Fluence Regions:

1) $\Phi t < 1x10^{20}$ n/cm^2

2) $1x10^{20}$ n/cm^2 $\leq \Phi t < 7x10^{20}$ n/cm^2

3) $7x10^{20}$ n/cm^2 $\leq \Phi t < 1x10^{21}$ n/cm^2

4) $1x10^{21}$ n/cm^2 $\leq \Phi t < 1x10^{22}$ n/cm^2

5) $1x10^{22}$ n/cm^2 $\leq \Phi t < 5x10^{22}$ n/cm^2

6) $5x10^{22}$ n/cm^2 $\leq \Phi t$

Notes:

1. Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA.
2. The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.
3. No additional measures

Intentionally Blank

The initial MRP-227A Inspection and Evaluation guidelines incorporated the experts' knowledge of applicable operating experience up to that time. Operating experience with reactor vessel internals components and materials has generally been positive, a trend which has continued since the original MRP-191, Revision 0, expert panel review. The SLR expert panel considered several relevant developments in operating experience for its review of the components:

- Guide plates/cards: Wear of the guide plates/cards was a known issue for Westinghouse-designed plants during the original MRP-191 expert panel review, with the guide cards being assigned to Category C for wear and then becoming a Primary inspection item in MRP-227-A/Revision 1. Exemption requirements for the guide plates/cards are consistent with MRP-2014-006 and WCAP-17451-P.
- Baffle-former bolts: IASCC degradation of the baffle-former bolts was a known issue for Westinghouse-designed plants during the original MRP-191 expert panel review, with the bolts being assigned to Category C in particular for IASCC and fatigue, and then becoming a Primary inspection item in MRP-227-A / Revision 1. Since the original expert panel review, a more severe iteration of baffle-former bolt degradation has been observed at multiple plants, where large clusters of adjacent bolts fail. This is thought to coincide with an acceleration of the rate of baffle-former bolt failures. The operating experience with baffle-former bolts was considered relevant for not only the baffle-former bolts, but also for similar bolts, such as the lower support column bolts and barrel-former bolts which have similar designs and have accumulated significant radiation dose.
- Reactor vessel head adapter thermal sleeve: Wear has been observed at several Westinghouse-designed plants in the reactor vessel head adapter thermal sleeves, but has not been observed for Surry Units 1 and 2. Unacceptable levels of wear have been observed in several cases, and in 2014, a thermal sleeve had worn through such that it was no longer held in position. Recent operating experience at an international plant indicates that wear of the thermal sleeves can impede the ability to insert a control rod assembly as described in Westinghouse Nuclear Safety Advisory Letter NSAL-18-1, Thermal Sleeve Flange Wear Leads to Stuck Control Rod.
- Clevis insert bolts: SCC degradation of the bolts that hold the clevis inserts in place in Westinghouse-designed plants has been observed at 2 U.S. plants. This has been attributed to the susceptible Alloy X-750 material of the bolts and primary water SCC.
- Clevis inserts and radial support keys: Wear of the alignment surfaces provided by the clevis insert and the radial support keys has been observed in both domestic and international Westinghouse-designed plants. This wear was listed as the focus for the Existing programs inspection included in MRP-227-A/Revision 1.

- Malcomized fuel alignment pins: Surface degradation of fuel alignment pins that were fabricated with a malcomized surface hardening treatment has been observed. This appears as a flaking off of a surface material. This could lead to accelerated wear and loss of material on the surface.
- Brackets, clamps, terminal blocks, and conduit straps: During the SLR expert panel review, it was noted that the clamps included for this grouping have experienced some amount of age-related degradation failures. It was thought that this degradation was likely due to SCC of cold-worked regions created during installation.

C3 SLR SCOPE AND SUSCEPTIBILITY FOR PWR VESSEL INTERNALS COMPONENTS

Initial license renewal implementation of aging management requirements for reactor vessel internals involved completing the following steps. Subsequent license renewal implementation of aging management requirements for the reactor vessel internals involved completing the following steps to ensure complete and accurate inclusion of requirements from MRP-227, Revision 1, which are applicable for a Westinghouse plant:

1. Identify the reactor vessel internals components (within the designated reactor vessel internals assembly and sub-assembly), material, and function requiring aging management.
2. Identify the degradation mechanisms for each of the applicable reactor vessel internals components.
3. Perform a failure modes, effects, and criticality analysis (FMECA) for each of the applicable components.
4. Screen the vessel internals components for degradation and provide categorization with respect to safety and economic consequences.
5. Assign risk and significance of degradation for each applicable component.
6. Determine whether aging management for each applicable component will be designated as a Primary activity, an Expansion activity, or an Existing activity.

C3.1 ASSEMBLY, SUB-ASSEMBLY, COMPONENT, MATERIAL, AND FUNCTION

The reference for the listing of reactor vessel internals components and materials for Surry Unit 1 and Unit 2 that require aging management is Westinghouse letter LTR-AMLR-17-35, “Transmittal of Preliminary Results from the MRP-191 Expert Panel Review in Support of Subsequent License Renewal for Surry Units 1 and 2,” Attachment 4. The functions for these components were obtained from the aging management review results documentation for the reactor vessel internals system in Table 3.1.2-2, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation. The component, material, and function information from that table is summarized in Table C3.1-1, Reactor Vessel Internals Sub-assembly Components, Materials, Functions. Table C3.1-1 lists all reactor vessel internals components that are within the scope of subsequent license renewal to confirm that aging effects will be managed for the subsequent period of extended operation. The listing provides compliance with Applicant / Licensee Action Item 2 from Revision 1 of the NRC Safety Evaluation Report for MRP-227, Revision 0 (ML11308A770).

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 1)	316 SS	Structural support
		C-tubes (Note 1)	304 SS	Structural support
		Guide tube enclosures (Note 1)	304 SS	Structural support
		Flanges - intermediate (Note 1)	304 SS	Structural support
			CF8	Structural support
		Flanges - lower	304 SS	Structural support
			CF8	Structural support
		Flexureless inserts (Unit 2 only) (Note 1)	304 SS	Structural support
		Flexures (Unit 1 only) (Note 1)	X-750	Structural support
		Guide plates (cards)	304 SS	Structural support
			CF8	Structural support
		Guide tube support pins	X-750 (U-1)	Structural support
		Guide tube support pins (Note 1)	316 SS (U-2)	Structural support
		Housing plates (Note 1)	304 SS	Structural support
			CF8	Structural support
		Inserts (Unit 1 only) (Note 1)	304 SS	Structural support
			CF8	Structural support
		Sheaths (Note 1)	304 SS	Structural support
		Support pin nuts	Alloy 600 (U-1)	Structural support
		Support pin nuts (Note 1)	316 SS (U-2)	Structural support
	Mixing devices	Mixing devices (Note 1)	CF8	Structural support
	Upper core plate and fuel alignment pins	Fuel alignment pins	304 SS	Structural support
		Upper core plate	304 SS	Structural support
		Upper core plate insert (Note 1)	304 SS	Structural support
		Upper core plate insert bolts (Note 1)	316 SS	Structural support
		Upper core plate insert locking devices and dowel pins (Note 1) (Note 2)	304L SS	Structural support
		Upper core plate insert locking devices and dowel pins (Note 1) (Note 2)	316 SS	Structural support
	Upper instrumentation conduit and supports	Bolting (Note 1)	316 SS	Structural support
			304 SS	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Upper internals assembly (cont'd)	Upper instrumentation conduit and supports (cont'd)	Brackets, clamps, terminal blocks, and conduit straps (Note 1)	304 SS	Structural support
			CF8	Structural support
		Conduit seal assembly: body, tubesheets, tubesheet welds (Note 1)	304 SS	Structural support
		Conduit seal assembly: tubes (Note 1)	304 SS	Structural support
		Conduits (Note 1)	304 SS	Structural support
		Flange base (Note 1)	304 SS	Structural support
		Locking caps (Note 1)	304L SS	Structural support
		Support tubes (Note 1)	304 SS	Structural support
	Upper support column assemblies	Adapters (Note 1)	304 SS	Structural support
		Bolts (Note 1)	316 SS	Structural support
		Column bases (Note 1)	CF8	Structural support
		Column bodies (Note 1)	304 SS	Structural support
		Extension tubes (Note 1)	304 SS	Structural support
		Flanges (Note 1)	304 SS	Structural support
		Lock keys (Note 1)	304 SS	Structural support
		Nuts (Note 1)	304 SS	Structural support
			302 SS	Structural support
	Upper support plate assembly – flat plate design	Upper support plate (Note 1)	304 SS	Structural support
		Upper support ring	304 SS	Structural support
		Deep beam ribs (Note 1)	304 SS	Structural support
		Deep beam stiffeners (Note 1)	304 SS	Structural support
		Bolts (Note 1)	316 SS	Structural support
		Locking device (Note 1)	304 SS	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 1)	304 SS	Structural support
		Baffle-edge bolts	316 SS	Structural support
		Baffle plates	304 SS	Flow distribution Structural support
		Baffle-former bolts	347 SS	Structural support
		Corner bolts	347 SS	Structural support
		Barrel-former bolts	347 SS	Structural support
		Former plates	304 SS	Structural support
	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	304 SS	Structural support
		BMI column bolts (Note 1)	316 SS	Structural support
		BMI column collars (Note 1)	304 SS	Structural support
		BMI column cruciforms (Note 1)	CF8	Structural support
		BMI column extension bars (Note 1)	304 SS	Structural support
		BMI column extension tubes (Note 1)	304 SS	Structural support
		BMI column locking devices (Note 1)	304L SS	Structural support
		BMI column nuts (Note 1)	304 SS	Structural support
	Core barrel	Core barrel flange	304 SS	Flow distribution Structural support
		Core barrel outlet nozzles	304 SS	Structural support
		Lower core barrel axial welds (includes MAW and LAW)	304 SS	Structural support
		Lower core barrel girth welds (includes LGW and LFW)	304 SS	Structural support
		Upper core barrel axial welds (includes UAW)	304 SS	Structural support
		Upper core barrel girth welds (includes UFW and UGW)	304 SS	Structural support
	Diffuser plate	Diffuser plate (Note 1)	304 SS	Flow distribution
	Flux thimble (tubes)	Flux thimble tube plugs (Note 1)	Alloy 600	Structural support
		Flux thimbles (tubes)	Alloy 600	Structural support
	Head cooling spray nozzles	Head cooling spray nozzles (Note 1)	304 SS	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Lower internals assembly (cont'd)	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 1)	316 SS	Structural support
		Irradiation specimen access plug (plug) (Note 1)	304 SS	Structural support
		Irradiation specimen access plug (spring) (Note 1)	X-750	Structural support
		Irradiation specimen guide (Note 1)	304 SS	Structural support
	Lower core plate and fuel alignment pins	Fuel alignment pins	304 SS	Structural support
		Lower core plate	304 SS	Structural support
	Lower support column assemblies	Lower support column bodies	CF8	Structural support
		Lower support column bolts	316 SS	Structural support
		Lower support column bolt locking devices (Note 1)	304L SS	Structural support
		Lower support column nuts (Note 1)	304 SS	Structural support
		Lower support column sleeves (Note 1)	304 SS	Structural support
	Lower support forging	Lower support forging	304 SS	Structural support
	Neutron panels/ thermal shield	Thermal shield bolts (Note 1)	316 SS	Structural support
		Thermal shield dowels (Note 1)	316 SS	Structural support
			304 SS	Structural support
		Thermal shield flexures	316 SS	Structural support
		Thermal shield flexure bolts (Note 1)	316 SS	Structural support
		Thermal shield flexure locking devices and dowel pins (Note 1) (Note 3)	304 SS	Structural support
			304L SS	Structural support
		Thermal shield (Note 1)	304 SS	Structural support
	Radial support keys	Radial support key bolts (Note 1)	316 SS	Structural support
		Radial support key dowels (Note 1)	304 SS	Structural support
			316 SS	Structural support
		Radial support key lock keys (Note 1)	304 SS	Structural support
		Radial support keys (Note 1)	304 SS	Structural support
		Radial support keys	Stellite	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Lower internals assembly (cont'd)	Secondary core support (SCS) assembly	SCS base plate (Note 1)	304 SS	Structural support
		SCS bolts (Note 1)	316 SS	Structural support
		SCS energy absorber (Note 1)	304 SS	Structural support
		SCS guide post (Note 1)	304 SS	Structural support
		SCS housing (Note 1)	304 SS	Structural support
		SCS lock keys (Note 1)	304 SS	Structural support
		Upper and lower tie plates (Note 1)	304 SS	Structural support
Interfacing components	Interfacing components	Clevis insert bolts	X-750	Structural support
		Clevis insert dowels	Alloy 600	Structural support
		Clevis insert locking devices (Note 1)	Alloy 600	Structural support
		Clevis inserts (Note 1)	Alloy 600	Structural support
		Clevis inserts	Stellite	Structural support
		Head and vessel alignment pin bolts (Note 1)	316 SS	Structural support
		Head and vessel alignment pins (Note 1)	304 SS	Structural support
		Internals hold-down spring	304 SS	Structural support
		Upper core plate alignment pins	304 SS	Structural support
			Stellite	Structural support
		Thermal sleeves	304 SS	Structural support
		Thermal sleeve guide funnels (Note 1) Unit 1	304 SS	Structural support
		Thermal sleeve guide funnels (Note 1) Unit 2	CF8	Structural support

Notes:

1 No additional measures
2 The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.
3 The thermal shield flexure locking devices are 304L SS and the dowel pins are 304 SS.

C3.2 SAFETY AND ECONOMIC CONSEQUENCE AND RISK CATEGORIZATION

Similar to MRP-227-A and MRP-227, Revision 1, MRP 2018-022 prescribes programs and activities that will assure the long-term safe and reliable operation of PWR vessel internals as they age through 80 years. One difference for this revision of guidelines for the *PWR Vessel Internals* program (B2.1.7) is the separation between effects from relevant economic risks for asset management and the impacts of safety risks. The SLR expert panel review utilized this separation between safety and economic considerations to focus on safety consequences during categorization. Descriptions for the categorization of those considerations are indicated in the following two tables:

Table C3.2-1 Safety Consequence Category Descriptions

Category	Description
None	The component has no screened-in degradation mechanism. No need to assess core damage probability.
Low	Expert panel believes there is no credible means for component failures(s) to cause core damage.
Medium	Expert panel believes the potential exists for core damage as a result of component (or multiple) failure(s) but that the ability to shut down the reactor in a controlled manner remains.
High	Expert panel believes that some core damage could possibly result from failure of the component(s).

Table C3.2-2 Economic Consequence Category Descriptions

Category	Description
None	No or trivial cost
Low	Cost that can be generally handled within the existing plant outage budget and resources (<$5M)
Medium	Cost that exceeds the normal plant outage budget and resources (>$5M)
High	Cost that potentially affects the utility's overall enterprise/financial health (>$20M)

The risk categorizations for safety consequences and economic consequences are summarized in the following two tables:

Table C3.2-3 Safety Consequence Risk Category Descriptions

Category	Description
Category A	Those component items for which aging effects are below the screening criteria. Aging degradation significance is minimal. The initial set of Category A components consists of items for which all degradation mechanisms are screened out. These components are identified as "None" in the appropriate columns of the screening and categorization tables. In addition, the FMECA results can identify additional components for which age-related degradation mechanisms have minimal likelihood to cause failure. These components are also assigned to Category A. This action essentially screens these components out of further consideration for future steps in developing MRP-227 for SLR. Additional components may ultimately be categorized as Category A as discussed in the Category B definition.
Category C	Those "lead" component items for which aging effects are above screening levels. Aging degradation significance is high or moderate. Enhanced/augmented inspections and/or surveillance sampling typically may be warranted to assess aging effects and verify component item safety functionality. These components, for which aging effects are above the threshold values of the screening criteria, are assessed to have moderate to high likelihood of occurrence, and have the potential for significant damage. Moreover, they have not been demonstrated, analytically or by experiment, to be sufficiently damage-tolerant to remain functional relative to the aging degradation mechanism(s) identified.
Category B	Category B items are defined as those component items that also are above screening levels but are not "lead" component items. Aging degradation significance is moderate. Category B component items may require additional evaluations to be shown tolerant of the aging effects with no loss of functionality (i.e., damage tolerant). Non-Category A components that are judged to have moderate susceptibility and potentially significant consequences, such that the effects on function cannot easily be dispositioned by screening, and yet are not considered Category C components, are assigned to Category B. Some of the components included in the Category B list may have been screened in for susceptibility to one or more degradation mechanisms, but the likelihood of occurrence and the implied safety risk were assessed by qualitative expert assessment to be low to moderate. If it is further concluded that the existing 10-year in-service inspection or other in-place aging management plans are sufficient to preclude a safety concern, such components can be reassigned as Category A.

Table C3.2-4 Economic Consequence Risk Category Descriptions

Category	Description
Category A	Those component items for which aging effects are below the screening criteria. Aging degradation significance is minimal. The initial set of Category A components consists of items for which all degradation mechanisms are screened out. These components are identified as “None” in the appropriate columns of the screening and categorization tables. In addition, the FMECA results can identify additional components for which age-related degradation mechanisms have minimal likelihood to cause failure. These components are also assigned to Category A. This action essentially screens these components out of further consideration for future steps in developing MRP-227 for SLR. Additional components may ultimately be categorized as Category A as discussed in the Category B definition.
Category C	Those “lead” component items for which aging effects are above screening levels. Aging degradation significance is high or moderate. Enhanced/augmented inspections and/or surveillance sampling typically may be warranted to assess aging effects and verify component item functionality, and identify extent of repairs that may be required (including likely cost and outage duration impacts). These components, for which aging effects are above the threshold values of the screening criteria, are assessed to have moderate to high likelihood of occurrence, and have the potential for significant economic or reliability consequences. Moreover, they have not been demonstrated, analytically or by experiment, to be sufficiently damage-tolerant to remain functional relative to the aging degradation mechanism(s) identified.
Category B	Category B items are defined as those component items that also are above the screening levels but are not “lead” component items. Aging degradation significance is moderate. Category B component items may require additional evaluations to be shown tolerant of the aging effects with no loss of functionality (i.e., damage tolerant). Non-Category A components that are judged to have moderate susceptibility and potentially significant economic consequences, such that the effects on function cannot easily be dispositioned by screening, and yet are not considered Category C components, are assigned to Category B. Some of the components included in the Category B list may have been screened in for susceptibility to one or more degradation mechanisms, but the likelihood of occurrence and the implied economic risk were assessed by qualitative expert assessment to be low to moderate. If it is further concluded that the existing 10-year in-service inspection or other in-place aging management plans are sufficient to preclude a reliability or functional concern, such components can be reassigned as Category A.

C3.3 FAILURE MODES, EFFECTS, AND CRITICALITY ANALYSIS (FMECA)

The outputs generated by the SLR expert panel review were developed based on a specific set of inputs. Those inputs include the list of components in scope, the materials of fabrication for those components, the calculated neutron fluence and dose, the stress and operating conditions assumed, and the known operating experience and plant modifications.

The following table lists the failure likelihood and consequence (damage likelihood) rankings that were applicable from MRP-191, Revision 0 and Revision 1:

Table C3.3-1 MRP-191, Revision 0/1 SLR Expert Panel Reactor Internals FMECA (Significance) Groups

Failure Likelihood	Consequence (Damage Likelihood)		
	Low	Medium	High
High	2	3	3
Medium	1	2	3
Low	1	1	2
None	0	0	0

The related values of failure likelihood and consequence rankings from MRP-191, Revision 2, are indicated in the following table:

Table C3.3-2 MRP-191, Revision 2 SLR Expert Panel Reactor Internals FMECA (Significance) Groups

Failure Likelihood	Consequence (Damage Likelihood)		
	Low	Medium	High
High	3	3	3
Medium	2	2	3
Low	1	1	2
None	0	0	0

Table C3.3-3 provides the results from the expert panel review. This table lists the following parameters for each of the PWR vessel internals components which requires aging management:

Screened-in degradation mechanisms, including the progression of degradation mechanisms from MRP-191, Revision 0; through MRP-191, Revision 1; to MRP-191, Revision 2.

- Likelihood of failure
- Safety consequence
- Economic consequence
- Safety FMECA group
- Economic FMECA group
- Safety consequence risk category
- Economic consequence risk category
- SLR inspection category

Similar to the expert panel outputs documented in MRP-191, Revision 1, the SLR expert panel review resulted in a number of components being assigned to the highest risk category. Some of those assignments were the result of both safety categorization and economic categorization, but more were for economic consequences alone.

Comparing the results from the SLR expert panel review to the previous results from MRP-191, Revision 1, shows that ten components were added to the group of Category C items:

Economic Risk Category C

- Upper core plate
- Brackets, clamps, terminal blocks, and conduit straps
- Baffle-former assembly bracket bolts [Not applicable for SPS]
- Thermal shield flexures
- Clevis insert bolts
- Internals hold-down spring

Safety and Economic Risk Category C

- Baffle-former assembly corner bolts
- Radial support keys (Stellite wear surface)
- Clevis inserts (Stellite wear surface)
- Thermal sleeves

As shown in Table C3.3-3 and summarized in Table C3.3-4, two Category C items from MRP-191, Revision 1, were moved to lower risk categories:

- Control rod guide tube (CRGT) assembly C-tubes
- Flux thimble (tubes)

Revised screening criteria, recent operating experience, and increases in time and neutron dose influenced the above increases in risk category. The decreases in risk category were related to revisions to risk based on actual operational impact, such as for the flux thimble tubes.

Table C3.3-4 provides a comparison of risk categorization between MRP-191, Revision 1, and those developed during the SLR expert panel review.

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 3)	316 SS	None	None	SCC, Fatigue	L	M	L	1	1	A	A	N
		C-tubes (Note 3)	304 SS	Wear	Wear	Wear, Fatigue	M	M	M	2	2	B	B	N
		Guide tube enclosures (Note 3)	304 SS	SCC-W, Wear	SCC-W	SCC-W, Fatigue	L	M	M	1	1	A	A	N
		Flanges - intermediate (Note 3)	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, Fatigue	L	M	M	1	1	A	A	N
			CF8	SCC-W, Fatigue, TE	SCC-W, Fatigue, TE	SCC-W, Fatigue, TE	L	M	M	1	1	A	A	N
		Flanges - lower	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, IASCC, Fatigue, IE	M	M	M	2	2	B	B	P
			CF8	SCC-W, Fatigue, TE, IE	SCC-W, Fatigue, TE, IE	SCC-W, IASCC, Fatigue, TE, IE	M	M	M	2	2	B	B	P
		Flexureless inserts (Unit 2 only) (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Flexures (Unit 1 only) (Note 3)	X-750	SCC	SCC	SCC, Fatigue	H	L	M	3	3	C	C	N
		Guide plates (cards)	304 SS	SCC-W, Wear, Fatigue	SCC-W, Wear, Fatigue	SCC-W, Wear, Fatigue	H	H	M	3	3	C	C	P
			CF8	--	SCC-W, Wear, Fatigue, TE, IE	SCC-W, Wear, Fatigue, TE	H	H	M	3	3	C	C	P

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Upper internals assembly (cont.)	Control rod guide tube assemblies and flow downcomers (cont'd)	Guide tube support pins	X-750 (U-1)	SCC, Wear, Fatigue, ISR/IC	SCC, Wear, Fatigue, ISR/IC	SCC, IASCC, Wear, Fatigue, IE, ISR/IC	H	L	M	3	3	C	C	X
		Guide tube support pins (Note 3)	316 SS (U-2)	Wear, Fatigue, ISR/IC	Wear, Fatigue, ISR/IC	IASCC, Wear, Fatigue, IE, ISR/IC	L	L	M	1	1	A	A	N
		Housing plates (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
			CF8	--	TE	TE	L	L	M	1	1	A	A	N
		Inserts (Unit 1 only) (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
			CF8	--	--	TE	L	L	L	1	1	A	A	N
		Sheaths (Note 3)	304 SS	Wear	Wear	Wear, Fatigue	H	H	M	3	3	C	C	N
		Support pin nuts	Alloy 600 (U-1)	--	--	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	X
		Support pin nuts (Note 3)	316 SS (U-2)	None	None	Fatigue, IE	L	L	M	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Upper internals assembly (cont.)	Mixing devices	Mixing devices (Note 3)	CF8	SCC-W, TE, IE	SCC-W, TE, IE	SCC-W, Fatigue, TE, IE	L	L	M	1	1	A	A	N
	Upper core plate and fuel alignment pins	Fuel alignment pins	304 SS	--	Wear	IASCC, Wear, Fatigue, IE	H	L	M	3	3	B	B	X
		Upper core plate	304 SS	Wear, Fatigue	Wear, Fatigue, IE	IASCC, Wear, Fatigue, IE	M	M	H	2	3	B	C	E
		Upper core plate insert (Note 3)	304 SS	--	--	Wear, IE	M	M	M	2	2	B	B	N
		Upper core plate insert bolts (Note 3)	316 SS	--	--	IASCC, Fatigue, IE, ISR/IC	L	L	M	1	1	A	A	N
		Upper core plate insert locking devices and dowel pins (Note 3)	*304L SS* (Note 2)	--	--	Fatigue, IE	L	L	M	1	1	A	A	N
		Upper core plate insert locking devices and dowel pins (Note 3)	316 SS (Note 2)	--	--	Fatigue, IE	L	L	M	1	1	A	A	N
	Upper instrumentation conduit and supports	Bolting (Note 3)	316 SS	None	None	None	--	--	--	0	0	A	A	N
			304 SS	--	None	None	--	--	--	0	0	A	A	N
		Brackets, clamps, terminal blks, conduit straps (Note 3)	304 SS	None	None	SCC, Fatigue	H	L	H	3	3	B	C	N
			CF8	--	TE	SCC, Fatigue, TE, IE	L	L	H	1	2	A	B	N
		Conduit seal assembly: body, tubesheets, tubesheet welds (Note 3)	304 SS	None	None	SCC, Fatigue	H	M	M	3	3	B	B	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Upper internals assembly (cont.)	Upper instrumentation conduit and supports (cont.)	Conduit seal assembly: tubes (Note 3)	304 SS	None	None	SCC, Fatigue	H	M	M	3	3	B	B	N
		Conduits (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		Flange base (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
		Locking caps (Note 3)	304L SS	None	None	Fatigue	L	L	M	1	1	A	A	N
		Support tubes (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
	Upper support column assemblies	Adapters (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		Bolts (Note 3)	316 SS	Wear, Fatigue, ISR/IC	Wear, Fatigue, ISR/IC	IASCC, Wear, Fatigue, IE, ISR/IC	L	L	M	1	1	A	A	N
		Column bases (Note 3)	CF8	SCC, TE, IE	SCC, TE, IE	SCC, IASCC, TE, IE	L	L	H	1	2	A	B	N
		Column bodies (Note 3)	304 SS	None	None	SCC-W, Fatigue	L	L	H	1	2	A	B	N
		Extension tubes (Note 3)	304 SS	SCC-W	SCC-W	SCC-W	L	L	H	1	2	A	B	N
		Flanges (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		Lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
		Nuts (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
			302 SS	--	None	Fatigue	L	L	M	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Upper internals assembly (cont.)	Upper support plate assembly – flat plate design	Upper support plate (Note 3)	304 SS	None	None	Fatigue	L	L	H	1	2	A	B	N
		Upper support ring	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, Fatigue	L	L	H	1	2	A	B	X
		Deep beam ribs (Note 3)	304 SS	SCC-W	SCC-W	SCC-W	L	L	L	1	1	A	A	N
		Deep beam stiffeners (Note 3)	304 SS	SCC-W	SCC-W	SCC-W	L	L	L	1	1	A	A	N
		Bolts (Note 3)	316 SS	None	None	SCC, Fatigue	L	L	L	1	1	A	A	N
		Locking device (Note 3)	304 SS	--	None	Fatigue	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 1	Screened-in Degradation Mechanisms[a] Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 3)	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	H	L	M	3	3	B	B	N
		Baffle-edge bolts	316 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	L	M	3	3	B	C	P
		Baffle plates	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	P
		Baffle-former bolts	347 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	M	M	3	3	C	C	P
		Corner bolts	347 SS	--	--	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	M	M	3	3	C	C	P (added by IG)
		Barrel-former bolts	347 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	L	M	3	3	B	C	E
		Former plates	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	P

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	304 SS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, Wear, Fatigue	M	L	L	2	2	B	B	E
		BMI column bolts (Note 3)	316 SS	Fatigue	Fatigue	IASCC, Wear, Fatigue, IE, VS, ISR/IC	M	L	M	2	2	B	B	N
		BMI column collars (Note 3)	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	M	L	L	2	2	B	B	N
		BMI column cruciforms (Note 3)	CF8	IASCC, TE, IE, VS	IASCC, TE, IE, VS	IASCC, Wear, Fatigue, TE, IE, VS	M	L	L	2	2	B	B	N
		BMI column extension bars (Note 3)	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	N
		BMI column extension tubes (Note 3)	304 SS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, Fatigue	L	L	L	1	1	A	A	N
		BMI column locking devices (Note 3)	304L SS	None	None	IASCC, IE, VS	L	L	L	1	1	A	A	N
		BMI column nuts (Note 3)	304 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Core barrel	Core barrel flange	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	M	H	1	2	B	B	P
		Core barrel outlet nozzles	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, Wear, Fatigue	L	M	H	1	2	B	B	E
		Lower core barrel axial welds (includes MAW and LAW)	304 SS	SCC-W, IASCC, IE	SCC-W, IASCC, IE	SCC-W, IASCC, Fatigue, IE, VS	M	M	H	2	3	B	C	E
		Lower core barrel girth welds (includes LGW and LFW)	304 SS	SCC-W, IASCC, IE	SCC-W, IASCC, IE	SCC-W, IASCC, Fatigue, IE, VS	M	M	H	2	3	B	C	P
		Upper core barrel axial welds (includes UAW)	304 SS	SCC-W, IASCC, IE	SCC-W, IE	SCC-W, Fatigue	M	M	H	2	3	B	C	E
		Upper core barrel girth welds (includes UFW and UGW)	304 SS	SCC-W, IASCC, IE	SCC-W, IE	SCC-W, Fatigue	M	M	H	2	3	B	C	P
	Diffuser plate	Diffuser plate (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	Alloy 600	--	SCC-W, IASCC, IE, VS	SCC-W, IASCC, Fatigue, IE, VS	M	L	L	2	2	B	B	N
		Flux thimbles (tubes)	Alloy 600	--	SCC-W, IASCC, Wear, IE, VS	SCC-W, IASCC, Wear, Fatigue, IE, VS	H	L	L	3	3	B	B	X
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Lower internals assembly (cont.)	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 3)	316 SS	--	--	None	--	--	--	0	0	A	A	N
		Irradiation specimen access plug (plug) (Note 3)	304 SS	IE	IE	None	--	--	--	0	0	A	A	N
		Irradiation specimen access plug (spring) (Note 3)	X-750	--	--	None	--	--	--	0	0	A	A	N
		Irradiation specimen guide (Note 3)	304 SS	Wear, IE	Wear, IE	SCC-W, Wear, Fatigue	L	L	L	1	1	A	A	N
	Lower core plate and fuel alignment pins	Fuel alignment pins	304 SS	--	IASCC, Wear, IE, VS	IASCC, Wear, IE, VS	H	L	M	3	3	B	B	X (added by IG)
		Lower core plate	304 SS	SCC-W, IASCC, Wear, Fatigue, IE, VS	SCC-W, IASCC, Wear, Fatigue, IE, VS	IASCC, Wear, Fatigue, IE, VS	L	M	H	1	2	A	B	X
	Lower support column assemblies	Lower support column bodies	CF8	IASCC, TE, IE, VS	IASCC, TE, IE, VS	IASCC, Fatigue, TE, IE, VS	L	L	L	1	1	A	A	E
		Lower support column bolts	316 SS	--	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	M	L	M	2	2	B	B	E
		Lower support column bolt locking devices (Note 3)	304L SS	--	--	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	N
		Lower support column nuts (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Lower support column sleeves (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Lower internals assembly (cont.)	Lower support forging	Lower support forging	304 SS	None	None	Fatigue	L	M	H	1	2	A	B	E
	Neutron panels/ thermal shield	Thermal shield bolts (Note 3)	316 SS	IASCC, Wear, Fatigue, IE, ISR/IC	IASCC, Wear, Fatigue, IE, ISR/IC	Fatigue, ISR/IC	H	L	L	3	3	B	B	N
		Thermal shield dowels (Note 3)	316 SS	IE	IE	Fatigue	L	L	L	1	1	A	A	N
			304 SS	--	IE	Fatigue	L	L	L	1	1	A	A	N
		Thermal shield flexures	316 SS	--	IASCC, Wear, Fatigue, IE, ISR/IC	SCC-W, Fatigue	M	L	H	2	3	B	C	P
		Thermal shield flexure bolts (Note 3)	316 SS	--	--	Fatigue, ISR/IC	L	L	L	1	1	A	A	N
		Thermal shield flexure locking devices and dowel pins (Note 3) (Note 4)	304 SS	--	--	Fatigue	L	L	L	1	1	A	A	N
			304L SS	--	--	Fatigue	L	L	L	1	1	A	A	N
		Thermal shield (Note 3)	304 SS	IE	IE	SCC-W, Fatigue, IE	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Radial support keys	Radial support key bolts (Note 3)	316 SS	--	Wear	Fatigue	L	L	L	1	1	A	A	N
		Radial support key dowels (Note 3)	304 SS	--	--	Fatigue	L	L	L	1	1	A	A	N
			316 SS	--	--	Fatigue	L	L	L	1	1	A	A	N
		Radial support key lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Radial support keys	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	M	M	1	1	A	A	P
		Radial support keys	Stellite	--	--	Wear	H	M	M	3	3	C	C	P (added by IG)
	Secondary core support (SCS) assembly	SCS base plate (Note 3)	304 SS	SCC-W	SCC-W	SCC-W, Fatigue	L	L	L	1	1	A	A	N
		SCS bolts (Note 3)	316 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		SCS energy absorber (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS guide post (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS housing (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Upper and lower tie plates (Note 3)	304 SS	--	None	Fatigue	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Interfacing components	Interfacing components	Clevis insert bolts	X-750	SCC, Wear	SCC, Wear	SCC, Wear	H	L	H	3	3	B	C	P (added by IG)
		Clevis insert dowels	Alloy 600	--	--	Fatigue	M	L	L	2	2	B	B	P (added by IG)
		Clevis insert locking devices (Note 3)	Alloy 600	None	None	Fatigue	L	L	L	1	1	A	A	N
		Clevis inserts	Alloy 600	Wear	Wear	Wear, Fatigue	L	L	H	1	2	A	B	P
			Stellite	Wear	Wear	Wear, Fatigue	H	M	H	3	3	C	C	P
		Head and vessel alignment pin bolts (Note 3)	316 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Head and vessel alignment pins (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Internals hold-down spring	304 SS	Wear	Wear	Wear, Fatigue	H	L	H	3	3	B	C	P
		Upper core plate alignment pins	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	L	M	1	1	A	A	X
			Stellite	--	--	Wear	M	L	M	2	2	A	B	X
		Thermal sleeves	304 SS	--	--	Wear	H	H	H	3	3	C	C	P
		Thermal sleeve guide funnels (Note 3) Unit 1	304 SS	--	--	Wear, TE	H	L	L	3	3	B	B	N
		Thermal sleeve guide funnels (Note 3) Unit 2	CF8	--	--	Wear, TE	H	L	L	3	3	B	B	N

a. Degradation mechanisms:

Stress corrosion cracking (SCC) [1A is applicable for SCC welds (SCC-W)]

Irradiation-assisted stress corrosion cracking (IASCC)

Wear

Fatigue (FAT)

Thermal aging embrittlement (TE)

Irradiation embrittlement (IE)

Void swelling (VS)

Thermal and irradiation-induced stress relaxation or irradiation creep (ISR/IC)

b. P = Primary, E = Expansion, X = Existing, N = No additional measures

c. Degradation mechanism added during Expert Panel review as indicated in LTR-AMLR-17-35 and LTR-AMLR-18-4.

Notes:

1. Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1). These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA.
2. The upper core plate insert locking devices are 304L SS, and the dowel pins are 316 SS.
3. No additional measures.
4. The thermal shield flexure locking devices are 304L SS and the dowel pins are 304 SS.

Intentionally Blank

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization: MRP-191, Revision 1 Category	Risk Categorization: SLR Expert Panel Safety Category	Risk Categorization: SLR Expert Panel Economic Category
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 3)		A	A	A
		C-tubes (Note 3)		C	B	B
		Guide tube enclosures (Note 3)		A	A	A
		Flanges - intermediate (Note 3)		A	A	A
				A	A	A
		Flanges - lower	304 SS	A	B	B
			CF8	B	B	B
		Flexureless inserts (Unit 2 only) (Note 3)		A	A	A
		Flexures (Unit 1 only) (Note 3)		C	C	C
		Guide plates (cards)	304 SS	C	C	C
			CF8	C	C	C
		Guide tube support pins	X-750 (Unit 1)	C	C	C
		Guide tube support pins (Note 3)	316 SS (Unit 2)	A	A	A
		Housing plates (Note 3)	304 SS	A	A	A
			CF8	A	A	A
		Inserts (Unit 1 only) (Note 3)	304 SS	A	A	A
			CF8	--	A	A
		Sheaths (Note 3)		C	C	C
		Support pin nuts	Alloy 600 (Unit 1)	--	Note 1	Note 1
		Support pin nuts (Note 3)	316 SS (Unit 2)	A	A	A
	Mixing devices	Mixing devices (Note 3)		A	A	A
	Upper core plate and fuel alignment pins	Fuel alignment pins		A	B	B
		Upper core plate		B	B	C
		Upper core plate insert (Note 3)		--	B	B
		Upper core plate insert bolts (Note 3)		--	A	A
		Upper core plate insert locking devices and dowel pins (Note 2) (Note 3)		--	A	A
		Upper core plate insert locking devices and dowel pins (Note 2) (Note 3)		--	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization		
				MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Upper internals assembly (cont.)	Upper instrumentation conduit and supports	Bolting (Note 3)	316 SS	A	A	A
			304SS	A	A	A
		Brackets, clamps, terminal blocks, and conduit straps (Note 3)	304 SS	A	B	C
			CF8	A	A	B
		Conduit seal assembly: body, tubesheets, tubesheet welds (Note 3)		A	B	B
		Conduit seal assembly: tubes (Note 3)		A	B	B
		Conduits (Note 3)		A	A	A
		Flange base (Note 3)		A	A	A
		Locking caps (Note 3)		A	A	A
		Support tubes (Note 3)		A	A	A
	Upper support column assemblies	Adapters (Note 3)		A	A	A
		Bolts (Note 3)		A	A	A
		Column bases (Note 3)		A	A	B
		Column bodies (Note 3)		A	A	B
		Extension tubes (Note 3)		A	A	B
		Flanges (Note 3)		A	A	A
		Lock keys (Note 3)		A	A	A
		Nuts (Note 3)	304 SS	A	A	A
			302 SS	A	A	A
	Upper support plate assembly – flat plate design	Upper support plate (Note 3)		A	A	B
		Upper support ring		B	A	B
		Deep beam ribs (Note 3)		A	A	A
		Deep beam stiffeners (Note 3)		A	A	A
		Bolts (Note 3)		A	A	A
		Locking device (Note 3)		A	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component	Risk Categorization		
			MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 3)	A	B	B
		Baffle-edge bolts	C	B	C
		Baffle plates	B	A	A
		Baffle-former bolts	C	C	C
		Corner bolts	--	C	C
		Barrel-former bolts	C	B	C
		Former plates	B	A	A
	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	B	B	B
		BMI column bolts (Note 3)	A	B	B
		BMI column collars (Note 3)	B	B	B
		BMI column cruciform (Note 3)	B	B	B
		BMI column extension bars (Note 3)	A	A	A
		BMI column extension tubes (Note 3)	B	A	A
		BMI column locking devices (Note 3)	A	A	A
		BMI column nuts (Note 3)	A	A	A
	Core barrel	Core barrel flange	B	B	B
		Core barrel outlet nozzles	B	B	B
		Lower core barrel axial welds (includes MAW and LAW)	C	B	C
		Lower core barrel girth welds (includes LGW and LFW)	C	B	C
		Upper core barrel axial welds (includes UAW)	C	B	C
		Upper core barrel girth welds (includes UFW and UGW)	C	B	C
	Diffuser plate	Diffuser plate (Note 3)	A	A	A
	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	B	B	B
		Flux thimbles (tubes)	C	B	B
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	A	A	A
	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 3)	--	A	A
		Irradiation specimen access plug (plug) (Note 3)	A	A	A
		Irradiation specimen access plug (spring) (Note 3)	--	A	A
		Irradiation specimen guide (Note 3)	A	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization: MRP-191, Revision 1 Category	Risk Categorization: SLR Expert Panel Safety Category	Risk Categorization: SLR Expert Panel Economic Category
Lower internals assembly (cont.)	Lower core plate and fuel alignment pins	Fuel alignment pins		A	B	B
		Lower core plate		B	A	B
	Lower support column assemblies	Lower support column bodies		B	A	A
		Lower support column bolts		B	B	B
		Lower support column bolt locking devices (Note 3)		--	A	A
		Lower support column nuts (Note 3)		A	A	A
		Lower support column sleeves (Note 3)		A	A	A
	Lower support forging	Lower support forging		A	A	B
	Neutron panels/ thermal shield	Thermal shield bolts (Note 3)		A	B	B
		Thermal shield dowels (Note 3)	316 SS	A	A	A
			304 SS	A	A	A
		Thermal shield flexures		B	B	C
		Thermal shield flexure bolts (Note 3)		--	A	A
		Thermal shield flexure locking devices and dowel pins (Note 3)	304 SS	--	A	A
			304L SS	--	A	A
		Thermal shield (Note 3)		A	A	A
	Radial support keys	Radial support key bolts (Note 3)		A	A	A
		Radial support key dowels (Note 3)	304 SS	--	A	A
			316 SS	--	A	A
		Radial support key lock keys (Note 3)		A	A	A
		Radial support keys	304 SS	A	A	A
			Stellite	--	C	C
	Secondary core support (SCS) assembly	SCS base plate (Note 3)		A	A	A
		SCS bolts (Note 3)		A	A	A
		SCS energy absorber (Note 3)		A	A	A
		SCS guide post (Note 3)		A	A	A
		SCS housing (Note 3)		A	A	A
		SCS lock keys (Note 3)		A	A	A
		Upper and lower tie plates (Note 3)		A	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization: MRP-191, Revision 1 Category	Risk Categorization: SLR Expert Panel Safety Category	Risk Categorization: SLR Expert Panel Economic Category
Interfacing components	Interfacing components	Clevis insert bolts		B	B	C
		Clevis insert dowels		--	B	B
		Clevis insert locking devices (Note 3)		A	A	A
		Clevis inserts	Alloy 600	A	A	B
			Stellite	A	C	C
		Head and vessel alignment pin bolts (Note 3)		A	A	A
		Head and vessel alignment pins (Note 3)		A	A	A
		Internals hold-down spring		B	B	C
		Upper core plate alignment pins	304 SS	B	A	A
			Stellite	--	A	B
		Thermal sleeves		--	C	C
		Thermal sleeve guide funnels (Note 3)		--	B	B

Notes:

1 Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA. AREVA performed an assessment of the CRGT support pins nuts for Surry Unit 1 and determined that no additional action is necessary to conform to MRP-227-A guidelines for the period of extended operation.

2 The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.

3 No additional measures

C4 PRIMARY, EXPANSION, OR EXISTING PROGRAMS INSPECTION REQUIREMENTS

Individual tables are provided to list the PWR vessel internals components which will require inspection for SLR. Each of these tables include applicable aging effects to be managed, the examination methods, and the examination coverage. Table C4.3-1 lists the Primary components to be examined. Table C4.3-2 includes the Expansion components. Table C4.3-3 lists the components which have Existing examinations.

C4.1 CHANGES TO THE CURRENT PRIMARY, EXPANSION, OR EXISTING PROGRAMS INSPECTION REQUIREMENTS

Seven components or component groups that are currently Primary, Expansion, or Existing inspections items in MRP-227, Revision 1, are expected to require changes for MRP-227, Revision 2:

Changes due to SLR expert panel review

- Baffle-former bolts (clarification for corner bolts)
- Baffle-edge bolts (clarification for bracket bolts, but bracket bolts are not applicable for the Surry units)

Potential changes due to NRC RAIs for MRP-227, Revision 1, or due to Interim Guidance

- Upper core plate
- Baffle-former bolts
- Baffle-former bolt expansion criteria
- Core barrel welds
- Lower support columns
- Lower support forging

Changes due to SLR expert panel review

- Baffle-former bolts

The SLR expert panel review added the corner bolts components under the baffle and former assembly. These bolts were not missed during the development of MRP-191, Revision 1 or MRP-227, Revision 1. In those documents, the corner bolts were assumed to be included under the baffle-former bolts since they were located in similar locations and performed similar functions. For the development of MRP-227, Revision 2, the SLR expert panel decided that additional clarity should be added by including the corner bolts by name.

All of the screening, categorization, and ranking conclusion for the baffle-former bolts are also applicable to the corner bolts.

Potential changes due to NRC RAIs for MRP-227, Revision 1, or due to Interim Guidance

- Upper core plate

  NRC RAI 14 for MRP-227, Revision 1 has questioned the reduction in inspection coverage and inspection technique from MRP-227-A to MRP-227, Revision 1 for the upper core plate. This could result in changes to the requirements of MRP-227, Revision 1, in an NRC-approved version.

- Baffle-former bolts

  As a response to the operating experience with baffle-former bolts, the industry developed MRP-2017-009, "Transmittal of NEI 03-08 'Needed' Interim Guidance Baffle Former Bolt Inspections for PWR Plants as Defined in Westinghouse NSAL 16-01 Rev. 1" that modified the initial inspection timing, evaluation criteria, and re-inspection interval for the bolts. The NRC staff assessed the technical basis behind the interim guidance and accepted the guidance for aging management of baffle-former bolts (Reference ML17310A861). NRC RAI 8 also asked a question about how the industry plans to respond to the baffle-former bolt experience, and the response was that the baffle-former bolt interim guidance MRP-2017-009 would be used.

- Baffle-former bolt Expansion criteria

  MRP-2018-002, ""Transmittal of NEI 03-08 'Needed' Interim Guidance Regarding MRP-227-A and MRP-227, Revision 1 Baffle-Former Bolt Expansion Inspection Requirements for PWR Plants" on the baffle-former bolt Expansion criteria was published to address cases where large clusters of degraded bolts of bolts with relevant indications were observed. MRP-2018-002 defined what is considered a large cluster of degraded bolts and provided a revised Expansion inspection requirement to visually inspect at least a portion of the barrel-former bolts if a large cluster of degraded baffle-former bolts is observed.

- Core barrel welds

  The response to RAI 5 provided a basis for reduced inspection coverage of the core barrel welds, and RAI 26 provided a basis for the assignment of welds to the Primary or Expansion component lists. MRP 2018-026 provides an update of the required inspections for the core barrel upper flange weld (UFW), upper girth weld (UGW), lower girth weld (LGW), lower flange weld (LFW), upper axial weld (UAW), middle axial weld (MAW), and lower axial weld (LAW) include additional examination coverage.

- Lower support columns

  The response to RAI 9 provided a basis for the reduced (25%) inspection coverage and VT-3 examinations for the lower support columns. These changes were implemented in MRP-227, Revision 1, and were included in MRP 2018-022.

- Lower support forging

The response to RAI 14 provided a basis for the reduced (25%) inspection coverage and VT-3 examination for the lower support forging. These changes were implemented in MRP-227, Revision 1, and were included in MRP 2018-022.

C4.2 ADDITIONAL COMPONENTS TO BE ADDED TO THE PRIMARY, EXPANSION, OR EXISTING PROGRAMS CATEGORIES

It is expected that five components or component groups will be added to the Westinghouse Primary, Expansion, or Existing component categories in MRP-227, Revision 1:

- Primary
  - Clevis insert bolts and dowels (elevated from Existing)
  - Thermal sleeves
  - Core barrel assembly radial support keys
  - Clevis inserts (elevated from Existing)
- Expansion
  - None
- Existing
  - Malcomized fuel alignment pins

Clevis Insert Bolts and Dowels

The experience in Westinghouse plants with clevis insert bolt cracking and clevis insert dowel degradation indicates that the clevis insert bolts and dowels need to be managed for potential aging degradation. The cracking of bolts was due to susceptibility of the Alloy X-750 bolts to primary water SCC. The degradation of the dowels was likely related to the same aging degradation mechanism. Based on the operating experience to date and the high susceptibility of this material, the SLR expert panel assigned the clevis bolts to safety risk Category B and economic risk Category C. The SLR expert panel also added the clevis insert dowels as a separate line item in MRP-191, and assigned the dowels to safety risk Category B.

The clevis insert bolts were included in both MRP-227-A and MRP-227, Revision 1, as an Existing inspection item. Due to the fact that degradation of the clevis insert bolts has been observed at multiple plants, the bolts have been elevated from Existing to Primary for MRP 2018-022. This elevation also is supported by the fact that no other component in the Westinghouse reactor vessel internals could effectively serve as a leading indicator for the primary water SCC that clevis insert bolts are expected to experience. Some degradation has been observed in the clevis insert bolts prior to the first PEO at 40 years. The re-inspection interval would be 10 years.

The general visual inspection (VT-3) of ASME Code Section XI that was specified for the clevis insert bolts may detect degradation of the bolts, but if the degradation is hidden beneath the head, it may not. Past inspection experience has shown that once bolts are fully separated and the heads have begun to wear on locking devices or the clevis insert, the VT-3 examination can detect degradation. Evaluation of clevis insert bolt cracking (PWROG-15034-P) has determined that degraded clevis insert bolts would not result in a loss of function of the lower radial support system, and thus should not pose a safety concern. Several physical constraints were shown to prevent this loss of function during operation. This technical basis supported the conclusion that the current general visual (VT-3) examinations from MRP-227 are sufficient to manage the safety function of the lower radial support system. Proactive replacement of these bolts would be an acceptable approach to manage the potential degradation.

The clevis insert dowels were not included in MRP-227, Revision 1, as a Primary, Expansion, or Existing Programs inspection component. Since degradation has already been observed in the dowels, they have been elevated in MRP 2018-022. The dowels are located directly adjacent to the clevis insert bolts, and the expected degradation (fractured tack welds on the dowels or rotation of the dowels) can be detected by the same general visual (VT-3) inspection specified for bolts. Thus, these two components are combined into the same Primary inspection requirement. Typically, the safety risk Category B assignment of the clevis insert bolts and dowels would not automatically result in the bolts being assigned a Primary inspection. However, multiple instances of active degradation and the potential for varying Existing component inspection requirements from plant-to-plant merit a more conservative aging management approach.

The degradation mechanism is equally likely to occur at any clevis insert bolt or dowel location, so the required coverage should be 100% of the accessible clevis insert bolts and dowels. All of the bolts and dowels are expected to be accessible.

Thermal sleeves

Wear of the reactor vessel head adapter thermal sleeve has been observed at several Westinghouse-designed plants. This has reached unacceptable levels in some cases and resulted in thermal sleeves breaking free from their normal position. The wear occurs in three locations: the thermal sleeve flange, the outer diameter of the sleeve, and the inner diameter of the sleeve.

Based on this operating experience and the potential for significant nuclear safety consequences and economic consequences, the SLR expert panel review concluded that these thermal sleeves have been assigned to both safety and economic risk Category C. Recent operating experience indicates that wear of the thermal sleeves scan impede the ability to insert a control rod assembly (NSAL-18-1, Thermal Sleeve Flange Wear Leads to Stuck Control Rod). This potential safety impact would increase the safety consequence and likely increase the safety risk category. For the purposes of the interim guidance, the safety risk category is raised to C.

No other component in the reactor vessel internals can provide a leading indication for the wear degradation that has been observed in the thermal sleeves, and the wear to date has resulted in failures. Based on these reasons and the potential impacts on safety, the thermal sleeves are assigned as Primary inspection components by MRP 2018-022.

Some aspects of the wear degradation in the thermal sleeves can be detected with a general visual examination, but much of the wear occurs in locations that are inaccessible to a visual inspection or in a manner which obscures effective visual detection of the wear. Therefore, the following techniques are recommended for detecting wear of the thermal sleeves:

- Ultrasonic test (UT) to detect inner diameter or outer diameter wear of the sleeves.
- Measurements of the height of the thermal sleeve funnels relative to the reactor vessel closure head to detect wear in the thermal sleeve flange.

The inspection should be conducted per the plant design-specific inspection recommendations in TB 07-02. The inspection recommendations include the type, coverage, and timing of the inspection. The inspection is identified in MRP 2018-027 as a NEI 03-08 Needed Inspection.

Wear Surfaces of the Radial Support Keys and Clevis Inserts

Wear on the Stellite hardfacing surfaces of the radial support keys and clevis inserts is a concern for the Westinghouse-design plants. These are mating components that provide alignment for the core barrel. This wear could particularly become an issue as plants continue operation into the second PEO. The SLR expert panel determined that the wear of the clevis inserts and radial support keys should be elevated to Category C for both safety and economics. The elevated safety concern was due to the fact that these provide a core support and safe shutdown function by limiting the amount of circumferential or radial displacement in the core barrel. The elevated economic concern stemmed from the high difficulty of repairing these components due to the precision fits that were required during the original fabrication. The same reasoning was deemed applicable to both components.

The clevis inserts were not included in MRP-227-A, but are included in MRP-227, Revision 1, as an existing inspection component. Based on the results of the expert panel review, the clevis inserts have been elevated to be a Primary inspection component. The radial support keys were not assigned to an inspection category in either MRP-227-A or MRP-227, Revision 1, and should also be added to the Primary inspection category based on the expert panel review results. Operating experience has shown that significant wear is already occurring on these components at some plants, and logically, this wear will continue to increase into the second PEO.

All locations are potentially susceptible to wear on these components, so the coverage requirement should be 100% of the radial support keys and 100% of the clevis inserts. The inspection must focus on the wear surfaces and look for evidence of excessive wear. The inspection type will be general visual (VT-3). Note that this inspection is intended to detect the presence of wear on these surfaces, but is not expected to be effective at measuring the full extent of material loss that may have occurred. Such measurements are beyond the scope of this existing inspection, but may be required for evaluation and disposition of a relevant condition. The re-inspection interval would be 10 years.

Malcomized Fuel Alignment Pins

Per Westinghouse Technical Bulletin TB-16-4, accelerated loss of material degradation has been observed on fuel alignment pins that have a malcomized surface. This was a surface commonly used at many early plants to increase the hardness and resistance to wear. The degradation appears as a thin layer of material flaking off of the surface. The fuel alignment pins on both the upper core plate and the lower core plate can be affected by this mechanism, if they are malcomized. Based on the known operating experience, the SLR expert panel assigned these fuel alignment pins to a high likelihood of degradation, but maintained a low safety consequence because of the evaluations documented in TB-16-4. The evaluations showed that the loss of the malcomized surface layer and the resulting larger gap between the fuel assemblies and the fuel alignment pins should have a small effect on fuel mechanical and reload design criteria, and on loss of coolant accident analyses. Thus the expert panel review assigned the malcomized fuel alignment pins to safety Category B.

The fuel alignment pins are inspected regularly under existing ASME Code Section XI requirements. This inspection is a general visual (VT-3) and is appropriate for detection of the loss of material that may occur. Coverage should be 100% of the accessible fuel alignment pins, since the degradation can occur on any of the malcomized locations. The re-inspection interval would be 10 years.

C4.3 COMPONENT DESIGNATIONS FOR PRIMARY, EXPANSION, OR EXISTING PROGRAMS INSPECTIONS

Aging management requirements for Primary, Expansion, and Existing Components are covered in the Tables noted below. A brief description of changes incorporated since the issue of MRP-227-A and source of changes are identified in the column titled “Source of Revision/Addition.”

Table C4.3-1, Primary Components

Table C4.3-2, Expansion Components

Table C4.3-3, Existing Programs Components

Table C4.3-1 Primary Components

Primary Item	Effect (mechanism)	Expansion Link (Note 1)	Examination Method / Frequency (Note 1)	Examination Coverage	Source of Revision/ Addition
Control Rod Guide Tube Assembly Guide plates (cards)	Loss of material (wear)	None	Visual (VT-3) inspections and quantitative measurements are performed. Per the requirements of WCAP-17451-P, the absence of significant degradation during the inspections in 2012, confirm that no additional inspection is required prior to the normal ten-year interval[a] (Note 2).	An update provided in MRP 2018-007 indicates wear measurements to be obtained in 37 of the 48 CRGT locations.	MRP-227, Rev. 1 added WCAP-17451-P, MRP-2018-007 supplements industry WCAP-17451-P requirements.
Control Rod Guide Tube Assembly Lower flange welds, LFW	Cracking (SCC, Fatigue) Irradiation Embrittlement (IE) and Thermal Embrittlement (TE) are applicable aging mechanisms	Remaining accessible CRGT assembly lower flange welds BMI column bodies (Note 3)	Enhanced visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examination on a ten-year interval.[b]	100% of outer (accessible) CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal on the individual periphery CRGT assemblies (Notes 4 and 5).	Rev. 1 added Expansion to remaining CRGT lower flange welds; Rev. 1 removed Expansion to items upper core plate and lower support forging; added 0.25 inch of base metal to examination coverage.
Core Barrel Assembly Upper flange weld; UFW	Cracking (SCC)	Upper girth weld (UGW) Lower flange weld (LFW) Upper axial weld (UAW) Lower support forging. (Note 3)	Enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examination on a ten-year interval.[c]	100% of the accessible weld length of one side of the UFW and ¾" of adjacent base metal shall be examined. (Notes 6 and 9).	MRP-227A initially established examination coverage. MRP-227, Rev 1, removed Expansion to core barrel outlet nozzles, and to lower support column bodies; Rev. 1 added Expansion to UGW, LFW, and UAW, and to lower support forging/casting; reduced coverage to 25%. However MRP 2018-026 increased the required examination coverage.
Core Barrel Assembly Lower girth weld; LGW (Note 8)	Cracking (SCC, IASCC, Fatigue) Irradiation Embrittlement (IE) is an applicable aging mechanism.	Middle and lower core barrel axial welds. Upper core plate. Lower support column bodies (cast). (Note 3)	Periodic enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examinations on a ten-year interval.[d]	100% of the accessible weld length of the OD of the LGW and ¾" of adjacent base metal shall be examined. (Note 9).	MRP 2018-022 added core barrel axial welds, upper core plate, and lower support column bodies as Expansion items. MRP 2018-026 revised the required examination coverage.

Table C4.3-1 Primary Components

Primary Item	Effect (mechanism)	Expansion Link (Note 1)	Examination Method / Frequency (Note 1)	Examination Coverage	Source of Revision/ Addition
Core Barrel Assembly Lower core barrel flange weld. (Notes 10 and 11)	Cracking (SCC, Fatigue)	None	Periodic enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examinations on a ten-year interval.[e]	100% of one side of the accessible surfaces of the selected weld and adjacent base metal (Notes 6 and 7).	
Baffle-Former Assembly Baffle-edge bolts (Note 12)	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads Irradiation embrittlement (IE) and irradiation-enhanced stress relaxation (ISR) are applicable aging mechanisms. (Note 15)	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.[f]	Bolts and locking devices on high fluence seams. 100% of components accessible from core side. (Note 13)	MRP-227A. SPS does not have bracket bolts.
Baffle-Former Assembly Baffle-former bolts Corner bolts. (Note 14)	Cracking (IASCC, Fatigue) Irradiation embrittlement (IE) and Irradiation-enhanced stress relaxation (ISR) are applicable aging mechanisms. (Note 15)	Lower support column bolts, Barrel-former bolts	Since Surry is a Tier 2b plant per NSAL-16-1, letter MRP 2017-009 requires that baseline volumetric (UT) examination be performed no later 30 EFPY. Since the Surry units have <3% indications with no clustering (per MRP 2017-009), subsequent UT examinations[g] are on a ten-year interval.[h] (Note 16)	100% of accessible bolts. (Note 12) Heads accessible from the core side. UT accessibility may be affected by complexity of head and locking device designs.	MRP-227, Rev. 1 added Note 9 to include corner bolts. MRP 2018-022 clarified by identifying corner bolts as component.
Baffle-Former Assembly Assembly (includes: baffle plates, baffle edge bolts, and indirect effects of assembly void swelling in former plates)	Distortion (void swelling), or Cracking (IASCC) that results in: • Abnormal interaction with fuel assemblies • Gaps along high fluence baffle joints • Vertical displacement of baffle plate near high fluence joints • Broken or damaged edge bolts, locking systems along high fluence baffle joints	None	Visual (VT-3) examination to check for evidence of distortion, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.[i]	Core side surface: as indicated by MRP-227-A Figures 4-24, 4-25, 4-26, and 4-27.	MRP-227, Rev. 1 clarifies extent of Examination Coverage

Table C4.3-1 Primary Components

Primary Item	Effect (mechanism)	Expansion Link (Note 1)	Examination Method / Frequency (Note 1)	Examination Coverage	Source of Revision/ Addition
Alignment and Interfacing Components Internals hold down spring	Distortion (Loss of load due to stress relaxation) (Note 17)	None	Direct measurement of spring height within three cycles of the beginning of (before or after) the first license renewal period. If the first set of measurements is not sufficient to assess remaining life, additional spring height measurements will be required.[j] (Note 17)	Measurements should be taken at several points around the circumference of the spring, with a statistically adequate number of measurements at each point to minimize uncertainty.	MRP-227A. A calculation of required hold down spring height for the 80-year design life confirms that the existing measured spring heights for both units are acceptable, and no further measurements are necessary
Alignment and Interfacing Components Clevis insert bolts Clevis insert dowels (Note 18)	Cracking (SCC), Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. [k] Subsequent examinations on a ten-year interval.	All clevis insert bolts and clevis insert dowels.	Clevis insert bolts elevated to the Primary category by MRP 2018-022; the scope is expanded to include clevis insert dowels.
Alignment and Interfacing Components Thermal sleeves	Loss of material (Wear)	None	Visual inspection for top of CRGTs and/or bottom of thermal sleeve guide funnel for indications of wear per MRP 2018-010 (TB-07-02). MRP 2018-027 implements this inspection as described in NSAL 18-1.	Wear surfaces for top of CRGT and/or bottom of thermal sleeve guide funnel per MRP 2018-010 (TB-07-02).	Added as a Primary component in MRP 2018-022.
Thermal Shield Assembly Thermal shield flexures	Cracking (fatigue) or Loss of Material (wear) that results in thermal shield flexures excessive wear, fracture, or full separation	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.[l]	100% of thermal shield flexures	MRP-227A
Radial Support Keys Radial support keys Stellite wear surfaces (Note 18)	Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces and radial support keys	Added as a Primary component in MRP 2018-022.
Alignment and Interfacing Components Clevis bearing Stellite wear surface (Note 18)	Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces and radial support keys	Added as a Primary component in MRP 2018-022.

a. During refueling outages in 2012, control rod guide tube (CRGT) assembly guide card VT-3 inspections were performed for Surry Units 1 and 2. The CRGT assemblies had been replaced in Unit 1 in the mid 1980's; the CRGT assemblies for Unit 2 were the original components. 20% of the CRGT assemblies were inspected for each unit. The criteria of WCAP-17451-P were not applicable in 2012. However, the results obtained in 2012 confirm that no unacceptable values of guide card wear were found, and the designated criterion zone for both units is the "green zone". The nominal guide card slot width for the 15x15 fuel used at Surry is 0.277 inch. The maximum measured values for the slot widths on the 80 guide cards inspected for Unit 1 was 0.2851 inch; the Unit 2 maximum was 0.2850 inch. The other parameter monitored for guide cards is the ligament length, and the nominal value is 0.1859 inch. The minimum value of ligament length was 0.165 inch for both units. These differences of 11%, or less, between nominal values and measured values indicate no concern for guide card wear. The subsequent inspection period typically would be set based on a predictive wear calculation. Considering the small amount of wear, no additional inspection is required prior to the planned 10-year re-inspection. Also, control rod drop times are trended relative to technical specification limits as an additional indicator for possible guide card degradation.

b. EVT-1 inspections performed in 2012 for Surry Units 1 and 2 found no unacceptable results for the lower flange welds during the 24 control rod guide tube assembly inspections that were performed for each unit.

c. In 2012, the upper core barrel flange welds were inspected using EVT-1 for both units. The weld examinations yielded acceptable results for both units.

d. 70.4% of the lower girth (circumferential) weld was inspected using EVT-1 in 2013 on Unit 1. When combined with the inspection of the upper girth weld, a total of 85% of the welds was examined. 71.6% of the lower girth weld was inspected in 2014 on Unit 2. When combined with the inspection of the upper girth weld, a total of 85.6% of the welds was examined. No unacceptable inspection results were found for either unit.

e. The lower core barrel flange weld was inspected in 2013 for Unit 1, and in 2014 for Unit 2. The inspection was performed from the exterior of the core barrel. Cleaning of the weld was not required. 82% of the weld circumference was inspected for Unit 1; 81.5% of the circumference was inspected for Unit 2. Coverage limitations occurred due to the narrow gap between the core barrel and the reactor cavity wall. No issues were identified.

f. Baffle-edge bolt VT-3 examinations were performed in 2010 for Unit 1 and in 2011 for Unit 2 (approximately 28 EFPY for each unit). 936 accessible edge bolts were inspected for each unit. The only Unit 1 degradation that was noted for baffle-edge bolts was a missing weld on one end of the locking bar on one bolt which was determined to be an original fabrication condition. No further action was recommended. For Unit 2, no degradation of baffle edge bolts was noted.

g. MRP 2017-009 allows, as an alternative for performing UT inspections, a proactive effort for bolting replacements, or a plant-specific evaluation using established methodologies (e.g., WCAP-15029-P-A or equivalent).

h. VT-3 and UT examinations of baffle-former bolts were performed in 2010 for Unit 1 (approximately 28 EFPY per 1-PT-4) and in 2011 for Unit 2 (approximately 28 EFPY per 2-PT-4). The entire population of 1088 bolts was inspected for both units. Surry Units 1 and 2 are designated Tier 2. For Unit 1, there were four findings. There were two bolts that were non-inspectable using UT due to deformation at the points on the hex heads that affected the back wall signal. However, reviews of the UT signals concluded no flaws. Those bolts were verified to be acceptable per VT-3 results. Most of the VT-3 inspection results were satisfactory. One bolt had unacceptable VT-3 results due to a missing locking bar weld on one end, but that was evaluated to be an original fabrication condition, and no further action was recommended. The UT result was satisfactory. One bolt was rejectable for UT results due to a flaw in the head-to-shank region, but had an acceptable VT-3 result. Corrective action recommended a VT-3 examination every other refueling outage to visually verify that the two welds on the baffle-bolt locking bar are intact with no visible signs of degradation.
For Unit 2, all VT-3 results were acceptable, but there were two reportable indications from the UT examinations. The visual examination for those two bolts showed no structural damage to the bolt head, locking bar or locking bar welds. The two indications were bounded by existing analysis which confirmed structural integrity and safety function of the reactor internals assembly.

i. VT-3 examinations were performed in 2013 for Unit 1 and in 2014 for Unit 2 (approximately 31 EFPY for each unit). Inspections of baffle plates, as an indication for indirect effects of void swelling, found no vertical displacement of the baffle plates. The baffle plates were vertical, and there was no evidence of warping or misalignment along the baffle seams. These findings are applicable for both units.

j. Direct measurements of the hold down spring height were performed for Unit 1 and Unit 2 in 2012. The measurements were obtained at 8 locations around the circumference of the spring. Three measurements were performed at each location. The results indicated an acceptable spring height that confirms the capability of the hold down spring to perform its intended function for 80 years of operation.

k. The clevis insert bolting was inspected for integrity during the 2013 and 2014 outages for Unit 1 and Unit 2, respectively. VT-3 exams were performed using VT-1 acuity. The enhanced visual acuity was used specifically to address industry OE concerns of clevis insert bolt cracking. No issues were identified.

l. VT-3 examinations were performed in 2013 for the six thermal shield flexures in Unit 1. The Unit 2 inspections for the six thermal shield flexures were performed in 2014. All inspection results were satisfactory; there was no evidence of cracking (fatigue) or loss of material (wear).

Notes:

1 Examination acceptance criteria and expansion criteria for the Westinghouse components are in Table 5-3 of MRP-227-A.

2 Examination method updated in MRP-227, Revision 1 based on issuance of WCAP-17451-P for industry use. Interim Guidance issued in PWROG Letter OG-18-76 amends the requirements regarding baseline examinations.

3 The FMECA expert panel determined that Surry would follow MRP-227, Revision 1, for the expansion inspection components of the CRGT lower flange welds, which include the remaining CRGT lower flange welds and the BMI column bodies. The lower support columns (cast) and the upper core plate are added as Expansion links to the lower core barrel girth weld (Primary), and the lower core support forging would be added as an Expansion link to the upper core barrel flange weld (Primary).

4 MRP-227-A Note: A minimum of 75% of the total identified sample population must be examined.

5 Clarification in MRP-227, Revision 1, to state that 0.25 inch of the adjacent base metal must be examined for the CRGT lower flange welds.

6 MRP-227-A Note: A minimum of 75% of the total weld length (examined + unexamined), including coverage consistent with the Expansion criteria in Table 5-3, must be examined from either the inner or outer diameter for inspection credit.

7 The examination coverage for core barrel welds was redefined in MRP-227, Revision 1.

8 The upper girth weld was moved to an Expansion link from the upper flange weld in MRP-227, Revision 1.

9 MRP 2018-026 revised the examination coverage to require a minimum of 50% of the circumference of either the ID or the OD of the weld being examined

10 MRP-227-A Note: The lower core barrel flange weld may be alternatively designated as the core barrel-to-support plate weld.

11 The lower flange weld was moved to an Expansion link from the upper flange weld in MRP-227, Revision 1.

12 Bracket bolts are not applicable to the Surry design.

13 MRP-227-A Note: A minimum of 75% of the total bolt population (examine + unexamined), including coverage consistent with the Expansion criteria in Table 5-3 of MRP-227, must be examined for inspection credit.

14 Corner bolts will be added as a Primary component in the next revision of MRP-227. They will be treated the same as baffle-former bolts.

15 MRP-227-A Note: Void swelling effects on the component are managed through management of void swelling on the entire baffle-former assembly.

16 Examination timing and frequency is updated in MRP-227, Revision 1, based in issuance of MRP 2017-009 for industry use.

17 Language clarified/simplified in MRP-227, Revision 1.

18 Added as a Primary component in MRP 2018-022.

Primary

Table C4.3-2 Expansion Components

Expansion Item	Effect (mechanism)	Primary Link (Note 1)	Examination Method / Frequency	Examination Coverage	Source of Revision/ Addition
Upper Internals Assembly Upper core plate	Cracking (Fatigue, wear)	Core barrel Lower Girth Weld (Note 2)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of accessible surfaces. (Notes 4 and 5)	MRP-227, Revision 1. MRP 2018-022 specified VT-3 examination and 25% coverage.
Control Rod Guide Tube Assembly Remaining CRGT lower flange welds (Note 6)	Cracking (SCC, Fatigue) Irradiation Embrittlement (IE) and Thermal Embrittlement (TE) are applicable aging mechanisms.	CRGT Lower Flange Welds (Notes 2 and 6)	Enhanced visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds. Subsequent examination on a ten-year interval.	A minimum of 75% of the CRGT assembly lower flange weld surfaces and 0.25 inch of the adjacent base metal for the flange welds not inspected under the Primary link.	MRP-227, Revision 1, added the requirement for 0.25 inch of adjacent base metal.
Bottom Mounted Instrumentation System Bottom-mounted instrumentation (BMI) column bodies	Cracking (Fatigue) including the detection of completely fractured column bodies. Irradiation Embrittlement (IE) is an applicable aging mechanism.	CRGT Lower Flange Welds (Note 2)	Visual (VT-3) examination of BMI column bodies as indicated by difficulty of insertion / withdrawal of flux thimbles. Re-inspection every 10 years following initial inspection. Flux thimble insertion / withdrawal to be monitored at each inspection interval.	100% of BMI column bodies for which difficulty is detected during flux thimble insertion/withdrawal.	MRP-227A
Core Barrel Assembly Middle axial weld (MAW) and Lower axial weld (LAW)	Cracking (SCC, IASCC) Irradiation Embrittlement (IE) is the applicable aging mechanism.	Lower core barrel cylinder girth weld (LGW)	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of the accessible weld length of the OD of the MAW and LAW and ¾" of adjacent base metal shall be examined. (Notes 4 and 9)	MRP 2018-026 changed the examination coverage.
Core Barrel Assembly Upper girth weld (UGW)	Cracking (SCC)	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of the accessible weld length of one side of the UGW and ¾" of adjacent base metal shall be examined (Note 9)	MRP-227, Revision 1, added the UGW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.

Table C4.3-2 Expansion Components

Expansion Item	Effect (mechanism)	Primary Link (Note 1)	Examination Method / Frequency	Examination Coverage	Source of Revision/ Addition
Core Barrel Assembly Lower flange weld (LFW)	Cracking (SCC)	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of the accessible weld length of the OD surface of the LFW and ¾" of adjacent base metal shall be examined. (Note 9)	MRP-227, Revision 1, added the LFW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.
Core Barrel Assembly Upper axial weld (UAW)	Cracking (SCC, IASCC) Irradiation Embrittlement (IE) is an applicable aging mechanism.	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of the accessible weld length of one side of the UAW and ¾' of adjacent base metal shall be examined (Note 9)	MRP-227, Revision 1, added the UAW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.
Lower Internals Assembly Lower support forging	Cracking (SCC)	Upper Core Barrel Flange Weld (UFW) (Note 2)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of the bottom surface. (Notes 4 and 5)	MRP-227, Revision 1, added this item to the Expansion category. MRP 2018-022 specified VT-3 examination and 25% coverage.
Lower Support Assembly Lower support column bodies (cast)	Cracking (IASCC) including detection of completely fractured column bodies. Irradiation Embrittlement (IE) is an applicable aging mechanism.	Lower core barrel girth Weld (Note 2)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of accessible support column assemblies as visible from above the lower core plate. (Note 4)	MRP-227, Revision 1, added this item to the Expansion category. MRP 2018-022 specified VT-3 examination and 25% coverage.
Core Barrel Assembly Barrel-former bolts (Note 7)	Cracking (IASCC, Fatigue) Irradiation Embrittlement (IE), void swelling, irradiation-enhanced stress relaxation (ISR) aging mechanisms	Baffle-former bolts	Volumetric (UT) examination Re-inspection every 10 years following initial inspection.	100% of accessible barrel-former bolts (minimum of 75% of the total population). Accessibility may be limited by presence of thermal shield or neutron pads. (Note 4)	MRP-227A

Table C4.3-2 Expansion Components

Expansion Item	Effect (mechanism)	Primary Link (Note 1)	Examination Method / Frequency	Examination Coverage	Source of Revision/ Addition
Lower Support Assembly Lower support column bolts	Cracking (IASCC, Fatigue) Irradiation embrittlement (IE), and irradiation-enhanced stress relaxation (ISR) are applicable aging mechanisms	Baffle-former bolts	Volumetric (UT) examination Re-inspection every 10 years following initial inspection.	100% of accessible lower support column bolts (minimum of 75% of the total population), or as supported by plant-specific justification. (Note 4)	MRP-227A

Notes:

1 Examination acceptance criteria and expansion criteria for the Westinghouse components are in Table 5-3 of MRP-227-A.

2 The FMECA expert panel determined that Surry would follow MRP-227, Revision 1, for the expansion inspection components of the CRGT lower flange welds, which include the remaining CRGT lower flange welds and the BMI column bodies. The lower support columns (cast) and the upper core plate are added as Expansion links to the lower core barrel girth weld (Primary), and the lower core support forging is added as an Expansion link to the upper core barrel flange weld (Primary).

3 MRP-227-A specifies an EVT-1 examination for the upper core plate, lower support forging, and lower support columns (cast). It is noted that in MRP-227, Revision 1, the inspection technique for these components is changed to a visual (VT-3) examination.

4 MRP-227-A Note: A minimum of 75% coverage of the entire examination area or volume, or a minimum sample size of 75% of the total population of like components of the examination is required (including both the accessible and inaccessible portions).

5 The examination coverage for the upper core plate, lower support forging, and lower support column bodies was redefined in MRP-227, Revision 1.

6 Remaining CRGT lower flange welds is added as an Expansion component in MRP-227, Revision 1, but as stated in Note 2 above, Surry will inspect in accordance with MRP-227, Revision 1 for this component.

7 MRP 2018-022 was issued on the baffle-former bolt expansion components which specifies that the lower support column bolts remain the first expansion component of the BFB unless a large cluster of BFB indications is discovered during the UT exams. The presence of clustering would trigger expansion of the barrel-former bolts adjacent to the large cluster of BFB indications due to the potential for clustering to result in indications of the barrel bolts. The terms “large cluster” and “barrel-former bolts adjacent to the cluster” are defined in MRP 2018-022.

8 The core barrel outlet nozzle welds are eliminated as an Expansion component in MRP-227. Revision 1.

9 The examination coverage for core barrel welds was redefined in MRP-227, Revision 1.

Table C4.3-3 Existing Programs Components

Item	Effect (mechanism)	Reference	Examination Method[a]	Examination Coverage	Source of Revision/ Addition
Control Rod Guide Tube Assembly Guide tube support pins and support pin nuts (Unit 1 only)	Cracking (SCC, Fatigue) Loss of material (wear) Irradiation embrittlement (IE) and Thermal and irradiation-induced stress relaxation (ISR/IC) are applicable aging mechanisms.	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency	MRP-227A
Core Barrel Assembly Core barrel flange	Loss of material (wear)	ASME Code Section XI, Category B-N-3	Visual (VT-3) exam to determine general condition for excessive wear.	All accessible surfaces at specified frequency.	MRP-227A
Upper Internals Assembly Upper support ring	Cracking (SCC, Fatigue)	ASME Code Section XI, Category B-N-3	Visual (VT-3) examination.	All accessible surfaces at specified frequency.	MRP-227A
Upper Internals Assembly Fuel alignment pins (Malcomized)	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Added by MRP 2018-022. See TB-16-4.
Lower Internals Assembly Lower core plate	Cracking (IASCC, Fatigue) Irradiation Embrittlement (IE) is an applicable aging mechanism.	ASME Code Section XI, Category B-N-3	Visual (VT-3) exam of the lower core plate to detect evidence of distortion and/or loss of bolt integrity.	All accessible surfaces at specified frequency.	Clarified with separate item created for wear by Rev. 1.
Lower Internals Assembly Lower core plate	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Clarified with separate item created for wear by Rev. 1.
Lower Internals Assembly Fuel alignment pins (Malcomized)	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Added by MRP 2018-022. See TB-16-4.
Bottom Mounted Instrumentation System Flux thimble tubes	Loss of material (wear)	IEB 88-09; Surry Augmented Inspection Program	Surface (ECT) examination.[b]	Eddy current surface examination for 100% of the accessible thimbles.	MRP-227A
Alignment and Interfacing Components Upper core plate alignment pins	Loss of material (wear).	ASME Code Section XI	Visual (VT-3) examination.	All accessible surfaces at specified frequency.	MRP-227A

a. Inspections for the components listed for Unit 1 were completed in November 2013. Inspections performed for Unit 2 were completed in May 2014.

b. Flux thimble tube inspections were completed in April 2015 for Unit 1 and in October 2015 for Unit 2. During the Unit 1 outage in 2015, 35 of the 50 flux thimble tubes were inspected using eddy current testing (ECT). 14 of those 15 remaining tubes were being replaced during that outage to complete the high pressure fitting / flux thimble tube replacement project that began in 2001. [The fifteenth tube would have been in location F-4, but that location had been capped in 2010 due to the inability to insert the new flux thimble tube]. Anomalies were noted in 2015 for two tubes identified as locations B7 and D7. For thimble tube B7, a through-wall pinhole leak was noted in the outer tube. The thimble tube was installed in 2004; an inspection in 2006 noted that thimble tube B-7 outer wall had been inadvertently damaged by plant personnel. Satisfactory eddy current results were obtained in 2015 for the inner tube which is the primary pressure boundary. Since the inner tube was not affected, thimble B-7 remained fully functional for flux mapping. For thimble tube D7, a dent is located approximately 5 feet below the seal table. Since the dent prevents the eddy current probe from passing, the thimble tube is no longer functional for passing an incore detector. The ECT for the Unit 2 flux thimble tubes found no indications of damage such as cracking and denting, or wall loss.

Intentionally Blank

Surry Power Station

Units 1 and 2

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.

Intentionally Blank