

SUBSEQUENT LICENSE RENEWAL APPLICATION

Nine Mile Point Nuclear Station, Unit 1

Renewed Facility Operating License No. DPR-63

March 2026

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1.0 ADMINISTRATIVE INFORMATION

1.1 GENERAL INFORMATION - 10 CFR 54.19

1.1.1 NAME OF APPLICANT

Constellation Energy Generation, LLC (CEG), hereby applies for a subsequent renewed operating license for Nine Mile Point Nuclear Station, Unit 1 (NMP1).

1.1.2 ADDRESS OF APPLICANT

Constellation Energy Generation, LLC
200 Energy Way
Kennett Square, PA 19348

1.1.3 DESCRIPTIONS OF BUSINESS OR OCCUPATION OF APPLICANT

Constellation Energy Generation, LLC is a Pennsylvania limited liability company which is wholly owned by Constellation Energy Corporation, a corporation formed under the laws of the Commonwealth of Pennsylvania. Constellation Energy Corporation, through its subsidiaries, is a major generator of electric power and a leading supplier of competitive electricity, with a current owned power generation portfolio of approximately 55 gigawatts of capacity from nuclear, natural gas, geothermal, hydro, wind and solar facilities. Constellation Energy Generation, LLC owns and operates the largest nuclear fleet in the United States. Constellation Energy Generation, LLC is the licensed operator of NMP1, which is the subject of this application. The current Nine Mile Point Nuclear Station, Unit 1 renewed operating license will expire at midnight on August 22, 2029 (Renewed Facility Operating License No. DPR-63).

Constellation Energy Generation, LLC will continue as the licensed operator on the subsequent renewed operating license.

1.1.4 DESCRIPTIONS OF ORGANIZATION AND MANAGEMENT OF APPLICANT

Constellation Energy Generation, LLC

Constellation Energy Generation, LLC is a limited liability company organized under the laws of the Commonwealth of Pennsylvania with its principal place of business in Kennett Square, Pennsylvania. Constellation Energy Generation, LLC is wholly owned by Constellation Energy Corporation, a corporation organized under the laws of the Commonwealth of Pennsylvania with its headquarters and principal place of business in Baltimore, Maryland. Constellation Energy Corporation is a publicly traded corporation whose shares are widely traded on the New York Stock Exchange. Constellation Energy Generation, LLC does not have a Board of Directors. All Principal Officers of Constellation Energy Generation, LLC are U.S. citizens. Constellation Energy Generation, LLC is not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. The Principal Officers of Constellation Energy Generation, LLC, and their addresses, are presented below:

Table 1.1-1
Principal Officers
(Constellation Energy Generation, LLC and Nuclear Business Unit)

Name	Title	Address
Bryan C. Hanson	Executive Vice President and Chief Generation Officer	1310 Point Street Baltimore, MD 21231
Christopher H. Mudrick	Senior Vice President, Constellation Energy Generation; President and Chief Nuclear Officer	200 Energy Way Kennett Square, PA 19348
Marri Marchionda-Palmer	Chief Operating Officer, Fleet Operations	4300 Winfield Road Warrenville, IL 60555
John J. Kowalski	Senior Vice President, Operations	4300 Winfield Road Warrenville, IL 60555
John P. Keenan	Senior Vice President, Operations	4300 Winfield Road Warrenville, IL 60555
Timothy C. Peter	Senior Vice President, Operations	348 Lake Road P.O. Box 63 Oswego, New York 13126
Michael F. Gillin	Senior Vice President, Operations	200 Energy Way Kennett Square, PA 19348
Mathew Price	Executive Vice President and General Counsel	250 Massachusetts Avenue, NW, Suite 760 Washington, DC 20001
Carrie Hill Allen	Senior Vice President and Deputy General Counsel, Regulatory Policy and Compliance	250 Massachusetts Avenue, NW, Suite 760 Washington, DC 20001
Frank Sturniolo	Senior Vice President Governance and Oversight	200 Energy Way Kennett Square, PA 19348
David M. Gullott	Vice President, Licensing and Regulated	4300 Winfield Road Warrenville, IL 60555
Carl Crawford	Site Vice President, Nine Mile Point	348 Lake Road P.O. Box 63 Oswego, New York 13126
Joeseph E. Pacher	Senior Vice President Engineering and Technical Services	200 Energy Way Kennett Square, PA 19348
David P. Lewis	Vice President, Engineering Growth	200 Energy Way Kennett Square, PA 19348

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

Constellation Energy Company, LLC requests a subsequent license renewal of the Class 104b renewed operating license for Nine Mile Point Nuclear Station, Unit 1 for a period of 20 years beyond the expiration of the current license to allow continued use of the facility for the commercial generation of electricity. Nine Mile Point Nuclear Station, Unit 1 license (DPR-63) expires at midnight on August 22, 2029.

In this application, Constellation Energy Generation, LLC also requests the renewal of specific licenses under 10 CFR Parts 30, 40, and 70 that are subsumed in or combined with the current renewed operating license.

1.1.6 EARLIEST AND LATEST DATES FOR ALTERATIONS, IF PROPOSED

No physical plant alterations or modifications have been identified as necessary in connection with this application.

1.1.7 RESTRICTED DATA

With regard to the requirements of 10 CFR 54.17(f), this application 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 be part of the licensed activities.

In accordance with the requirements of 10 CFR 54.17(g), the applicant 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

Constellation Energy Generation, LLC recovers its share of the costs incurred from operating NMP1 in its own wholesale rates. The wholesale rates charged and services provided by Constellation Energy Generation, LLC are subject to regulation by the Federal Energy Regulatory Commission under the Federal Power Act.

Federal Energy Regulatory Commission
888 First St. N.E.
Washington, DC 20426

The state of New York has limited jurisdiction over Nine Mile Point Nuclear Station (NMPNS) to include emergency preparedness and environmental regulations.

New York State Public Service Commission
Empire State Plaza
Agency Building 3
Albany, NY 12223-1350

1.1.9 LOCAL NEWS PUBLICATIONS

News publications in circulation near NMPNS that are considered appropriate to give reasonable notice of the application are as follows:

Palladium Times
140 West First Street
Oswego, NY 13126

The Post Standard
c/o Advance Media New York
1900 Grant Street
Buffalo, NY 14209

Oswego County Today
117 Cayuga Street
Fulton, NY 13069

1.1.10 CONFORMING CHANGES TO STANDARD INDEMNITY AGREEMENT

10 CFR 54.19(b) requires that “each application must 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-36) for NMPNS states, in Article VII, that the agreement “shall terminate at the time of expiration of that license specified in Item 3 of the Attachment.” As updated in Amendment 15, Item 3 of the Attachment to the indemnity agreement lists license number DPR-63 (for NMP1) and does not contain a specific expiration term. Applicant requests that any necessary conforming changes be made to Article VII and Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate to ensure that the indemnity agreement continues to apply during both the term of the current license and the term of the renewed license. Applicant understands that no changes may be necessary for this purpose if the current NMP1 license number is retained. Note that current Amendment 21 updated Item 1 of the Attachment to identify Constellation Energy Generation, LLC as the licensee.

1.2 GENERAL LICENSE INFORMATION

1.2.1 APPLICATION UPDATES, RENEWED LICENSES, AND RENEWAL TERM OPERATION

In accordance with 10 CFR 54.21(b), during NRC review of this application, annual updates to the application to reflect any change to the current licensing basis that materially affects the contents of the subsequent license renewal application will be provided.

In accordance with 10 CFR 54.21(d), Constellation Energy Generation, LLC will maintain a summary description in the NMP1 Updated Final Safety Analysis Report (UFSAR) of programs and activities that are required to manage the effects of aging for the systems, structures, and components determined to be subject to aging management during the subsequent period of extended operation, and summaries of the time-limited aging analyses evaluations.

1.2.2 INCORPORATION BY REFERENCE

There are no documents incorporated by reference as part of the application. Any document references, either in text or in Section 1.7 are listed for information only.

1.2.3 CONTACT INFORMATION

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

Christopher D. Wilson
 Director License Renewal
 Constellation Energy Generation, LLC
 200 Energy Way
 Kennett Square, PA 19348
Christopher.Wilson2@constellation.com

with copies to:

Sarah Brochu
 License Renewal Engineering Manager
 Peach Bottom APS
 1848 Lay Rd
 Delta, PA 17314
Sarah.Brochu@constellation.com

1.3 PURPOSE

This document provides information required by 10 CFR 54 to support the application for a subsequent renewed license for Nine Mile Point Nuclear Station, Unit 1. The application 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

The Nine Mile Point Nuclear Station consists of two nuclear plants, on approximately 846 acres along the shore of Lake Ontario, Oswego County, NY, approximately 5 miles north-northeast of the nearest boundary of the city of Oswego. NMP1 is a boiling water reactor (BWR) designed by the General Electric Company (GE). NMP1 is a GE type 2 reactor design with a 213-inch diameter vessel. The primary containment is of the Mark 1 design that consists of a drywell, a suppression chamber in the shape of a torus, and interconnecting vent piping for the main coolant system. NMP1 is authorized to operate at a steady state reactor core power level not in excess of 1850 MWt. The steam and power conversion system, including its turbine generator, is designed to permit generation of a net electrical output of approximately 615 MWe.

The major interconnected structures associated with NMP1 are the reactor building, which encloses the reactor vessel and the other primary containment system structures, refueling and reactor servicing equipment, and fresh and spent fuel storage facilities; the turbine building, which houses the turbine generator, feedwater heaters, and main condensers; the radioactive waste building; the screen house and pumphouse; the off gas building; and the administration building. NMP1 uses once-through cooling from Lake Ontario.

Descriptions of the NMP1 systems and structures can be found in the UFSAR. Additional descriptive information about the NMP1 systems, structures, and components is also provided in Section 2 of this application.

1.5 **APPLICATION STRUCTURE**

This subsequent license renewal application is structured in accordance with Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Plant Operating Licenses," Revision 2 and NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal." 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." NUREG-2192 references NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report." 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.

The application is divided into the following major sections:

Section 1 – Administrative Information

This section 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 section are the names, addresses, business descriptions, and organization and management descriptions of the applicant, as well as other administrative information. This section also provides an overview of the structure of the application, general references, and a listing of acronyms used throughout the application.

Section 2 – Structures and Components Subject to Aging Management Review

This section describes and justifies the methods used in the integrated plant assessment to identify those systems, 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 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 systems, structures, and components that perform their intended function 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 and screening results for systems and structures are described in this section. Scoping results are presented in Section 2.2, "Plant Level Scoping Results." Screening results are presented in Sections 2.3, 2.4, and 2.5.

The screening results consist of lists of passive long-lived mechanical and structural components that require aging management review. Brief descriptions of mechanical systems and structures within the scope of subsequent license renewal

are provided as background information. Mechanical system and structure intended functions are provided for in scope systems and structures. For each in scope system and structure, components requiring an aging management review are identified; associated component intended functions are identified; and appropriate reference to the Section 3 table providing the aging management review results is made.

Selected components, such as component supports and passive electrical components, were more effectively scoped and screened as commodities. Under the commodity approach, these component groups were evaluated based upon common environments and materials. Commodities requiring an aging management review are presented in Sections 2.4 and 2.5. Component intended functions and reference to the applicable Section 3 table are provided.

Section 3 – Aging Management Review Results

10 CFR 54.21 (a)(3) requires a demonstration that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis throughout the subsequent period of extended operation. Section 3 presents the results of the aging management reviews. Section 3 provides the link between the scoping and screening results provided in Section 2, the aging management programs provided in Appendix B, and the time-limited aging analyses (TLAA) evaluations provided in Section 4.

Aging management review results are presented in tabular form, in a format in accordance with NUREG-2192. For mechanical systems, aging management review results are provided in Sections 3.1 through 3.4 for the Reactor Vessel, Internals, and Reactor Coolant System; Engineered Safety Features; Auxiliary Systems; and Steam and Power Conversion Systems, respectively. Aging management review results for containments, structures, and component supports are provided in Section 3.5. Aging management review results for electrical and instrumentation and controls are provided in Section 3.6.

Tables are provided in each of these sections in accordance with NUREG-2192, which provide aging management review results for components, materials, environments, and aging effects which are addressed in NUREG-2191, and information regarding the degree to which the proposed aging management programs are consistent with those recommended in NUREG-2191.

Section 4 – Time-Limited Aging Analyses

Time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3, are listed in this section. This section includes a screening of the generic TLAAs identified in NUREG-2192 and the results of a review of the current licensing basis for plant-specific TLAAs. This section includes a summary of the time-dependent aspects of the analyses. A demonstration is provided to show that the analyses remain valid for the subsequent period of extended operation, the analyses have been projected to the end of the subsequent period of extended operation, or the effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation, consistent with 10 CFR 54.21(c)(1)(i)-(iii).

Appendix A –Updated Final Safety Analysis Report Supplement

As required by 10 CFR 54.21(d), the Updated Final Safety Analysis Report (UFSAR) supplement contains a summary of activities credited for managing the effects of aging for the subsequent period of extended operation. In addition, summary descriptions of TLAA evaluations are provided. NUREG-2191 Tables X-01 and XI-01, FSAR Supplement Summaries for GALL-SLR Report Chapters X and XI Aging Management Programs, respectively, were used as guidance for the content of the applicable aging management program summaries. Following issuance of the renewed license, the information contained in this appendix, as updated through the NRC review process, will be incorporated into the UFSAR.

Appendix B – Aging Management Programs

Appendix B describes the programs and activities that are credited for managing aging effects for components and structures during the subsequent period of extended operation based upon the aging management review results provided in Section 3 and the time-limited aging analyses results provided in Section 4.

Sections B.2 and B.3 discuss those programs that are contained in Section XI and Section X, respectively, of NUREG-2191. A description of the aging management program is provided, and a conclusion is drawn based upon the results of an evaluation to each of the ten elements provided in NUREG-2191. In some cases, exceptions and justifications for managing aging are provided for specific NUREG-2191 program elements. Additionally, operating experience related to the aging management program is provided, including an assessment of the effectiveness of aging management activities in place for the first period of extended operation, where applicable.

Appendix C – Response to BWRVIP License Renewal Applicant Action Items

This Appendix provides the requested responses to applicant action items contained in the NRC safety evaluation reports associated with NRC approved Boiling Water Reactor Vessel and Internals Program reports.

Appendix D – Technical Specification Changes

This Appendix satisfies the requirement in 10 CFR 54.22 to identify technical specification changes or additions necessary to manage the effects of aging during the subsequent period of extended operation. There were no technical specification changes identified necessary to manage the effects of aging during the subsequent period of extended operation.

Appendix E – Environmental Information – Nine Mile Point, Unit 1

This Appendix satisfies the requirements of 10 CFR 54.23 to provide a supplement to the environmental report that complies with the requirements of subpart A of 10 CFR Part 51 for Nine Mile Point Nuclear Station, Unit 1.

1.6 **ACRONYMS**

Acronym	Meaning
A/LAI	Applicant/Licensee Action Item
AAC	All aluminum conductor
AC	Alternating current
ACAR	Aluminum conductor aluminum alloy reinforced
ACI	American Concrete Institute
ACSR	Aluminum conductor steel reinforced
ADS	Automatic depressurization system
AERM	Aging effects requiring management
ALE	Adverse localized environment
AMP	Aging Management Program
AMR	Aging Management Review
ANSI	American National Standards Institute
AOT	Abnormal operating transient
APRM	Average power range monitors
ARI	Alternate rod injection
ART	Adjusted Reference Temperature
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
AST	Alternative source term
ASTM	American Society for Testing and Materials
ATWS	Anticipated transient without scram
BTP	Branch technical position
B&W	Babcock and Wilcox
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owner's Group
BWRVIP	Boiling Water Reactor Vessel and Internals Project
C (°C)	Degrees Celsius
CA	Compressed air
CAMP	Cable Aging Management Software
CAP	Corrective action program
CAR	Condenser air removal and off-gas
CASS	Cast austenitic stainless steel
CDBI	Component Design Basis Inspection

Acronym	Meaning
CDF	Core damage frequency
CE	Combustion Engineering
CEG	Constellation Energy Generation, LLC
CF	Chemistry factor
CFR	Code of Federal Regulations
CFRP	Carbon fiber reinforced polymer
CLB	Current licensing basis
CLTP	Current licensed thermal power
CMAA	Crane Manufacturers Association of America
CMTR	Certified material test report
CO ₂	Carbon dioxide
CP	Cathodic protection
CRD	Control Rod Drive
CRDA	Control rod drop accident
CRDRL	Control Rod Drive return line
CRV	Control Room HVAC
CS	Core spray
CSE	Copper/copper sulfate reference electrode
CST	Condensate storage tank
CT	Current transformer
CTS	Condensate and condensate transfer
CTSP	Containment spray
CUF	Cumulative usage factor
CUF _{en}	Environmentally adjusted cumulative usage factor
CWS	Circulating Water System
DBA	Design basis accident
DBD	Design bases document
DBE	Design basis event
DH	Down horizontal
DLRO	Digital low resistance ohmmeter
DOR	Division of Operating Reactors
DORT	Two-Dimensional Discrete Ordinates Transfer Code
DPA	Displacement per atom
EAF	Environmentally assisted fatigue
EB	Electric Steam Boiler
EC	Emergency Cooling

Acronym	Meaning
ECCS	Emergency Core Cooling System
ECIV	Emergency condenser isolation valve
ECP	Electrochemical corrosion potential
EDG	Emergency Diesel Generator
EMA	Equivalent margin analysis
EFPY	Effective full power years
EOCI	Electric Overhead Crane Institute
EOI	End-of-interval
EOL	End-of-life
EPRI	Electric Power Research Institute
EPC	Erosion in Piping and Components
EPU	Extended power uprate
EQ	Environmental qualification
ERV	Electromatic relief valve
ESF	Engineered safety features
EVT	Enhanced visual test
F (°F)	Degrees Fahrenheit
FAC	Flow-accelerated corrosion
FASA	Focused area self-assessment
F _{en}	Environmental fatigue correction factor
FERC	Federal Energy Regulatory Commission
FHA	Fuel handling accident
FLRA	First license renewal application
FP	Fire Detection and Protection
FPC	Spent Fuel Pool Cooling and Storage
FSWOL	Full structural weld overlay
FW	Feedwater
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal (GALL- SLR) Report
GE	General Electric Company
GL	Generic Letter
GSI	Generic safety issue
H	Horizontal
HAZ	Heat affected zone
HCU	Hydraulic control unit
HDPE	High-density polyethylene

Acronym	Meaning
HELB	High energy line break
HPCI	High Pressure Coolant Injection
HVAC	Heating, ventilation, and air conditioning
HWC	Hydrogen water chemistry
HX	Heat exchanger
I&C	Instrumentation and controls
IAC	Instrument air compressor
IASCC	Irradiation-assisted stress corrosion cracking
IBA	Intermediate break accident
ICMH	In-core monitor housing
ID	Inside diameter
IDLH	Immediately dangerous to life or health
IEB	IE Bulletin
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	Intergranular stress corrosion cracking
ILRT	Integrated leak rate test
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IPA	Integrated plant assessment
IR	Issue report
IRM	Intermediate range monitor
ISI	Inservice inspection
ISG	Interim staff guidance
ISP	Integrated surveillance program
IVVI	In-vessel visual inspection
KOH	Potassium hydroxide
KSI	Kilo pounds per square inch
kV	Kilovolt
LAS	Low alloy steel
LCM	Loss control manual
LER	Licensee event report
LERF	Large early release frequency
LRBD	License renewal boundary drawing
LLRT	Local leak rate test
LOCA	Loss of coolant accident

Acronym	Meaning
LOM	Loss of material
LP	Liquid poison
LPCI	Low-pressure coolant injection
LRA	License renewal application
LTAM	Long term asset management
LTR	Licensing Topical Report
MD	Makeup demineralizer
MEB	Metal enclosed bus
MELB	Medium energy line break
MG	Motor-generator
MGA	Main generator and auxiliary
MIC	Microbiologically influenced corrosion
MPM	MP Machinery and Testing
MRP	Materials Reliability Program
MS	Main steam
MSIV	Main steam isolation valve
MSLB	Main steam line break
MTA	Main turbine and auxiliaries
MWt	Megawatts-thermal
N ₂	Nitrogen
NACE	National Association of Corrosion Engineers
NDE	Nondestructive examination
NDT	Nil-ductility temperature
NDDT	Nil-ductility transition temperature
NEI	Nuclear Energy Institute
NEIL	Nuclear Electric Insurance Limited
NFPA	National Fire Protection Association
NMCA	Noble metal chemical addition
NMPNS	Nine Mile Point Nuclear Station
NMP1	Nine Mile Point Nuclear Station, Unit 1
NOC	Normal operating conditions
NOS	Nuclear oversight
NPO	Non-power operation
NPS	Nominal pipe size
NPSH	Net positive suction head
NRC	Nuclear Regulatory Commission

Acronym	Meaning
NRR	Office of Nuclear Reactor Regulation
NSAC	Nuclear Safety Analysis Center
NSCA	Nuclear Safety Capability Assessment
NSI	Next scheduled inspection
NSR	Nonsafety-related
NTTF	Near Term Task Force
NWC	Normal water chemistry
OBE	Operational basis earthquake
OD	Outside diameter
OE	Operating experience
OFS	Orificed fuel support
OGB	Offgas building
OLTP	Original licensed thermal power
P&ID	Piping and instrumentation diagram
PH	Precipitation hardened
PM	Preventive maintenance
PRA	Probabilistic risk assessment
PSI	Pounds per square inch
PT	Dye penetrant testing
P-T	Pressure-temperature
PTLR	Pressure and temperature limits report
PUAR	Plant Unique Analysis Report
PVC	Polyvinyl chloride
PWR	Pressurized Water Reactor
PWSCC	Primary water stress corrosion cracking
QATR	Quality assurance topical report
RAI	Requests for additional information
RBCLC	Reactor building closed loop cooling system
RBCW	Reactor Building Closed Loop Cooling
RBV	Reactor building HVAC
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor coolant system
RCSC	Research Council on Structural Connections
RFO	Refueling outage
RFP	Reactor feedwater pump
RG	Regulatory Guide

Acronym	Meaning
RI	Responsible individual
RIC	Recurring internal corrosion
RI-ISI	Risk-informed inservice inspection
RIPB	Risk-informed, performance-based
RMI	Reflective metallic insulation
ROV	Remote-operated vehicle
RPS	Reactor Protection System
RPT	Recirculation pump trip
RPV	Reactor pressure vessel
RPVI	Reactor pressure vessel internals
RR	Reactor recirculation
RSSB	Radwaste solidification and storage building
RT _{NDT}	nil-ductility reference temperature
Δ RT _{NDT}	Change in nil-ductility reference temperature
RTD	Resistance temperature detector
RT _{MAX}	Maximum reference temperature
RV	Reactor vessel
RVI	Reactor vessel internals
RW	Radwaste
RWCU	Reactor Water Cleanup
S _A	Stress range
SBA	Small break accident
SBO	Station blackout
SCC	Stress corrosion cracking
SDC	Shutdown cooling
SER	Safety evaluation report
SFP	Spent fuel pool
S _h	Allowable stress
SIA	Structural Integrity and Associates
SLC	Standby Liquid Control
SLR	Subsequent license renewal
SLRA	Subsequent license renewal application
SME	Subject matter expert
SO ₂	Sulfur dioxide
SPEO	Subsequent period of extended operation
SR	Safety-related

Acronym	Meaning
SRB	Sulfate reducing bacteria
SRM	Source range monitor
SRP	Standard Review Plan
SRV	Safety relief valve
SS	Stainless steel
SSCs	Systems, structures, and components
SSD	Safe shutdown
SSE	Safe shutdown earthquake
SW	Service water
TAN	Total acidity number
TAP	Torus attached piping
TBCW	Turbine building closed loop cooling water
TBV	Turbine building HVAC
TLAAs	Time-limited aging analyses
TORT	Three-Dimensional Discrete Ordinates Transfer Code
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UH	Up horizontal
UHS	Ultimate heat sink
USE	Upper-shelf energy
UT	Ultrasonic test
UV	Ultraviolet
VFLD	Vessel flange leak detection
VT	Visual test
WO	Work order
XRF	X-ray fluorescence
OT	Inside surface

1.7 GENERAL REFERENCES

- 1.7.1 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”
- 1.7.2 NEI 95-10, Revision 6, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule,” June 2005
- 1.7.3 NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,” December 2017
- 1.7.4 Regulatory Guide 1.188, Revision 2, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses”
- 1.7.5 NUREG-2192, Revision 1, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants”
- 1.7.6 NUREG-2191, Revision 1, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report”
- 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 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”
- 1.7.13 10 CFR 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions”
- 1.7.14 NUREG-0800, Section 9.5.1.1, Appendix B, “Supplemental Fire Protection Review Criteria for License Renewal,” Revision 5, March 2007
- 1.7.15 NUREG-0933, “Resolution of Generic Safety Issues,” U.S. Nuclear Regulatory Commission, Supplement 35, September 2021
- 1.7.16 EPRI Technical Report 3002011822, “Long-Term Operations: Subsequent License Renewal Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools,” April 2018
- 1.7.17 EPRI Report 3002010401, “Long-Term Operations: Subsequent License Renewal Electrical Handbook,” April 2018

- 1.7.18 EPRI Report 3002013084, “Long-Term Operations: Subsequent License Renewal Aging Effects for Structures and Structural Components (Structural Tools),” November 2018
- 1.7.19 NUREG-1900, “Safety Evaluation Report Related to the License Renewal of Nine Mile Point Nuclear Station, Units 1 and 2,” September 2006

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

For the systems, structures, and components (SSCs) within the scope of subsequent license renewal, 10 CFR 54.21(a)(1) requires the applicant to identify and list those structures and components subject to Aging Management Review (AMR). This section describes and justifies the process for identifying and listing those structures and components subject to aging management review in the Nine Mile Point Nuclear Station, Unit 1 (NMP1) subsequent license renewal integrated plant assessment, as required by 10 CFR 54.21(a)(2).

The 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* is the process of identifying the in scope structures and components that are subject to an aging management review in accordance with 10 CFR 54.21(a)(1). A detailed description of the scoping and screening process is provided in Section 2.1.

The scoping and screening methodology is consistent with the guidelines presented in NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal Rule (Reference 1.7.3). 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
- Section 2.4 for structures and component supports
- Section 2.5 for electrical

2.1. SCOPING AND SCREENING METHODOLOGY

2.1.1 INTRODUCTION

This introduction provides an overview of the scoping and screening process used at Nine Mile Point Nuclear Station, Unit 1 (NMP1). Subsequent sections provide details of 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 systems and structures were evaluated against the scoping criteria in 10 CFR 54.4, to determine if the system or structure is in scope for subsequent license renewal. A system or structure is included within the scope of subsequent license renewal if any portion of the system or structure meets one or more of the scoping criteria of 10 CFR 54.4. The intended function(s) that are the bases for including each system and structure within the scope of subsequent license renewal were also identified. Systems and structures determined to be within the scope of subsequent license renewal were then further evaluated to identify those structures and components that are required to perform or support the identified intended function(s).

Subsequent license renewal system descriptions were developed for each in scope mechanical system and are included in Section 2.3. These descriptions include relevant information from system descriptions included in the UFSAR. The in scope boundaries of mechanical systems are depicted on the subsequent license renewal boundary drawings (LRBD) by the use of boundary flags which identify subsequent license renewal system boundaries and interfaces. The in scope boundaries of the mechanical systems are shown highlighted in green or red. Mechanical components that are required to perform or support safety-related functions or are required to demonstrate compliance with one of the four license renewal regulated events applicable to BWRs are shown highlighted in green. Nonsafety-related mechanical components that are required only to provide structural support to safety-related SSCs are shown highlighted in red. Nonsafety-related mechanical components that are included within the scope of subsequent license renewal only because component failure could prevent the accomplishment of a safety-related function due to potential spatial interaction with safety-related SSCs are also shown highlighted in red. The NMP1 subsequent license renewal application incorporates the latest guidance for consideration of spatial interaction, defined in NEI 95-10, Revision 6, Appendix F (Reference 1.7.2), as referred to in NEI 17-01. The evaluation for spatial interactions is described in more detail below in the subsection titled "Potential for Spatial Interactions with Safety-Related SSCs" in Section 2.1.5.2. Additional details on system scoping evaluations and boundary drawing development are provided in Section 2.1.5.

Subsequent license renewal structure descriptions were developed for each in scope structure and are included in Section 2.4. These descriptions include relevant information from structure descriptions included in the UFSAR. Structures that support or protect SSCs that are included in scope under 10 CFR 54.4(a)(1) are highlighted in green on site plan drawings. Other in scope structures are highlighted in red. Additional details on structure scoping evaluations and boundary drawing development are provided in Section 2.1.5.

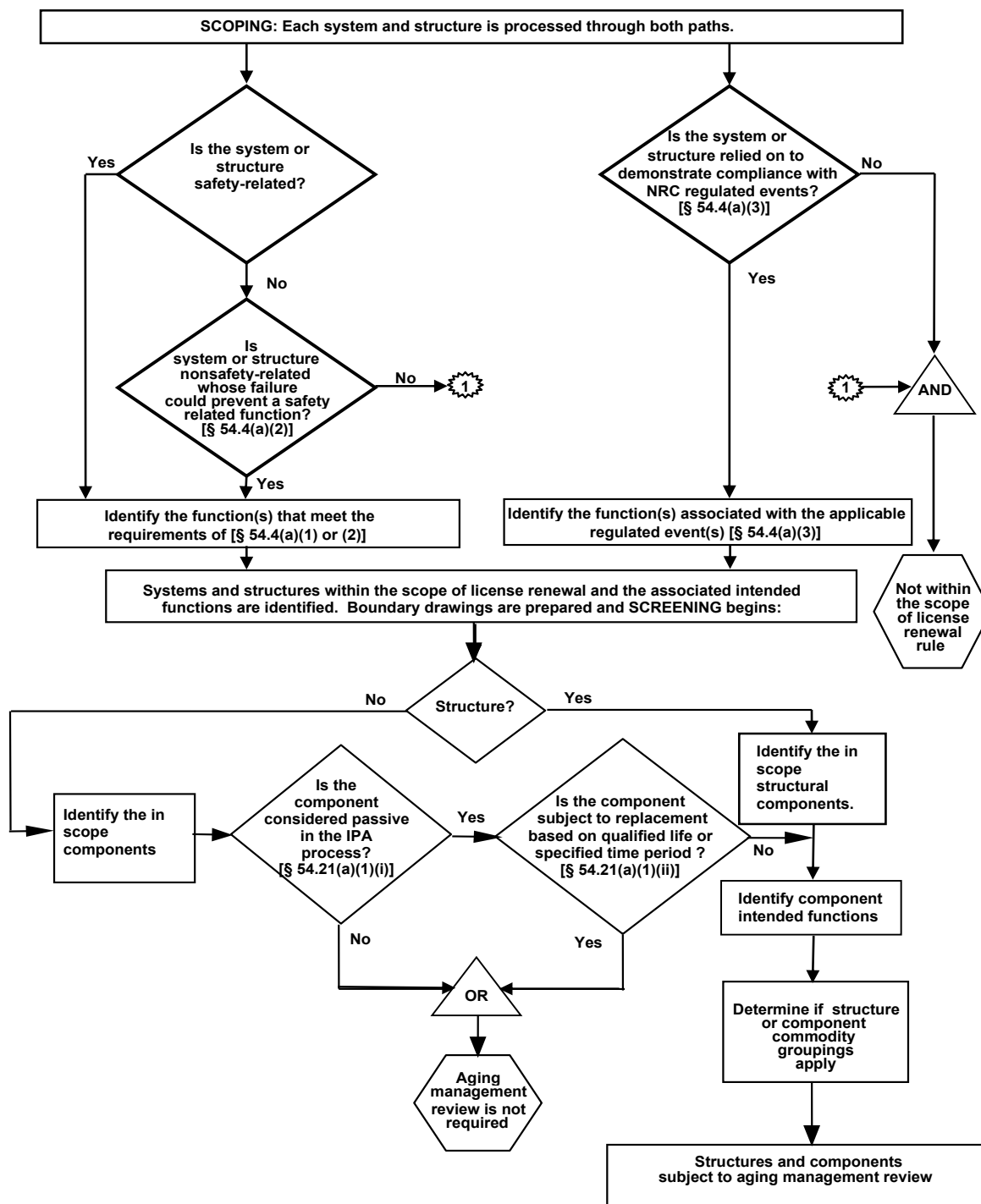
Electrical and Instrumentation and Control (I&C) systems were scoped similar to mechanical systems and structures in accordance with the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3). Electrical and I&C components within the in scope electrical and I&C systems were included within the scope of subsequent license renewal. Likewise, electrical and I&C components within the in scope mechanical systems were included within the scope of subsequent license renewal. The majority of the electrical and I&C components are active or are addressed as structural commodities (panels, conduit, cable trays, etc.). The passive, long-lived electrical and I&C components in scope for subsequent license renewal are addressed as commodity components independent of system associations. Therefore, electrical and I&C system descriptions are not included in the subsequent license renewal application. Additional details on electrical and I&C system scoping are provided in Section 2.1.5.

After completion of the scoping and boundary evaluations, the screening process identified the structures and components within the scope of subsequent license renewal that are passive, long-lived and subject to an Aging Management Review (AMR). In addition, the passive intended functions of structures and components subject to AMR were identified. Passive long-lived structures and components are identified consistent with Table 2.1-6 of NUREG-2192, Revision 1, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" (Reference 1.7.5). Additional details on the screening process are provided in Section 2.1.6.

Selected components, such as component supports, hazard barriers and elastomers, electrical and instrumentation enclosures and raceways, 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. Passive structural commodities are identified in Section 2.4 and passive electrical commodities are identified in Section 2.5.

Figure 2.1-1 provides a flowchart of the general scoping and screening process for mechanical systems, structures, and electrical systems.

Figure 2.1-1
Nine Mile Point Nuclear Station, Unit 1 Scoping and Screening Flowchart



2.1.2 INFORMATION SOURCES USED FOR SCOPING AND SCREENING

A number of different current licensing basis (CLB) and design basis information sources were utilized in the scoping and screening process. The CLB for NMP1 is consistent with the definition provided in 10 CFR 54.3. 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

The NMP1 Updated Final Safety Analysis Report (UFSAR), which is updated regularly in accordance with the requirements of 10 CFR 50.71(e), provided significant input for system and structure descriptions and functions.

2.1.2.2 Fire Protection Program

The following documents discuss the Fire Hazards and major Fire Protection Program commitments and as such, constitute the bases for the Fire Protection Program at NMP1:

- a. NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," 2001 Edition

The aforementioned document is described in the NMP1 UFSAR in Chapter X, Section K. NFPA 805 identifies fire protection systems and features required to meet the Chapter 1 performance criteria through the methodology in Chapter 4 of NFPA 805. Also, under NFPA 805, the 10 CFR 50.48(a)(2)(iii) requirement to limit fire damage to SSCs important to safety so that the capability to achieve and maintain safe and stable shutdown is satisfied by meeting the performance criteria in Section 1.5.1 of NFPA 805.

2.1.2.3 Environmental Qualification Master List

The scope of the electrical equipment and components that must be environmentally qualified for use in a harsh environment at NMP1 is identified in the component database. The component database is discussed in Section 2.1.2.6. The database includes a listing of equipment and components and includes fields that identify specific equipment information such as manufacturer, plant location, and qualification level. The component database Environmental Qualification (EQ) data field is a mandatory, design-quality field, and is an accurate record of the NMP1 commitment to 10 CFR 50.49.

2.1.2.4 Maintenance Rule Database

The Maintenance Rule Database documents the results of Maintenance Rule scoping for NMP1 systems and structures. The Maintenance Rule Database provided an additional source of information to identify system and structure functions.

2.1.2.5 Engineering Drawings

Engineering drawings at NMP1 provide system, structure, and component configuration details and safety classification information. These drawings were utilized to determine SSC functional requirements and materials of construction in support of scoping and screening evaluations.

2.1.2.6 Controlled Plant Component Database

NMP1 maintains a controlled plant component database that contains component level design and maintenance information. The plant component database is called Asset Suite 9. The component database lists plant components at the level of detail for which discrete maintenance or modification activities typically are performed. The component database provides a comprehensive listing of plant components and their quality classifications. Unique equipment component tag numbers identify each component in the database.

2.1.2.7 Other CLB References

NRC Safety Evaluation Reports include NRC staff review of NMP1 licensing submittals. Some of these documents may identify licensee commitments.

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.

Engineering evaluations and calculations can provide additional information about the requirements or characteristics associated with the evaluated systems, structures, or components.

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 basis documents. Basis documents contain technical evaluations and bases for decisions or positions associated with subsequent license renewal requirements as described below. Basis documents were prepared, reviewed, and approved in accordance with controlled 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 NMP1 scoping and screening methodology.

2.1.3.1 Subsequent License Renewal Systems and Structures List

One of the first steps necessary to begin the subsequent license renewal scoping process was to identify a comprehensive list of plant systems and structures to be evaluated for subsequent license renewal scoping. A basis document was prepared to establish this list and to document the basis for the list. While the component database is the primary source for identifying plant systems and

structures appropriate for subsequent license renewal consideration, other sources of information were reviewed to validate that all plant systems and structures were identified. The following resources were evaluated for additional information and insight to ensure the list of plant systems and structures is complete: the NMP1 UFSAR, plant piping and instrumentation diagrams (P&IDs), site plan drawings, the Maintenance Rule Database, and the Structural Monitoring Program, as well as plant walkdowns.

Plant systems and structures identified through review of the design and licensing basis references identified above were arranged into logical groupings for scoping reviews, and these groupings were defined as subsequent license renewal systems and structures. Commodity groups were also established to facilitate a focused aging management review process. These commodity groups include component supports, structural, and electrical commodities.

The 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
- Structures and Component Supports
- Electrical Systems

This grouping of the NMP1 subsequent license renewal systems and structures is based on the guidance of NUREG-2191, Revision 1, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report" (Reference 1.7.6). The complete list of systems, structures, and commodity groups evaluated for subsequent license renewal is provided in Section 2.2 of this application.

Certain structures and equipment were excluded at the outset because they are not considered to be systems, structures, or components that are part of the CLB and do not have design or functional requirements related to the 10 CFR 54.4(a)(1), (a)(2), or (a)(3) scoping criteria. These include driveways and parking lots, temporary equipment, health physics equipment, portable measuring and testing equipment, tools, and motor vehicles.

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. NMP1 plant systems and structures that have been designed to safety-related standards are identified in the UFSAR. NMP1 plant components that have been classified as safety-related are identified as "SR" in the engineering details data field in the component database. NMP1 safety classification procedures were reviewed against the subsequent license renewal "Safety-related" scoping criterion in 10 CFR 54.4(a)(1), to confirm that NMP1 safety-related classifications are consistent with subsequent license renewal requirements. This review is included

in a technical basis document. The basis document also provides a summary list of the systems and structures that are safety-related at NMP1. These systems and structures are included within the scope of subsequent license renewal in accordance with the 10 CFR 54.4(a)(1) scoping criterion.

Plant systems, structures, and components are defined as safety-related if they are necessary to ensure:

- The integrity of the reactor coolant pressure boundary,
- The capability to shut down the reactor and maintain it in a safe condition, or
- The capability to prevent or mitigate the consequences of postulated accidents which could result in potential offsite exposures comparable to those referred to in 10 CFR Part 100.11.

This definition is similar to the 10 CFR 54.4(a)(1) definition of safety-related SSCs, with the following clarifications:

Design Basis Events

The NMP1 procedure definition of safety-related does not specifically refer to design basis events, while 10 CFR 54.4(a)(1) refers to design basis events as defined in 10 CFR 50.49(b)(1). For NMP1 subsequent license renewal, an additional technical basis document was prepared to confirm that all applicable design basis events were considered. The basis document includes a review of all systems and structures that are relied upon to remain functional during and following design-basis events as defined in 10 CFR 50.49(b)(1). This includes confirming that design basis events including design basis accidents (DBAs), anticipated operational occurrences, external events, and natural phenomena as described in the current licensing basis (CLB) are considered when scoping for subsequent license renewal. Safety-related systems and structures required to support 10 CFR 54.4(a)(1) functions are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1).

Exposure Limits

The license renewal rule refers to exposure limits as defined in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable. These different exposure limit requirements appear in three different Code sections to address similar accident analyses performed by licensees for different reasons. The exposure limits in 10 CFR 50.34(a)(1) are applicable to facilities seeking a construction permit and are, therefore, not applicable to NMP1 subsequent license renewal.

The original UFSAR Chapter XV accident analyses were performed to address 10 CFR 100 guidelines. For the postulated fuel handling accident (FHA), control rod drop accident (CRDA), main steam line break (MSLB) accident outside containment, and loss of coolant accident (LOCA), a new set of radiological consequence analyses are presented in support of a full scope implementation of Alternative Source Term (AST) methodology in accordance with Regulatory Guide 1.183. The dose consequences for these limiting design basis accidents result in doses that are within the guidelines of 10 CFR 50.67.

When supplemented with the broad review of CLB design basis events, the NMP1 procedure 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. This is consistent with the guidance in 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 2.1.5.1.

2.1.3.3 10 CFR 54.4(a)(2) Scoping Criteria

All 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. To ensure complete and consistent application of this scoping criterion, a technical basis document was prepared.

This license renewal scoping criteria requires consideration of the following:

1. Functional (a)(2) – A nonsafety-related SSC that is functionally relied upon in the CLB to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or (b) directly mitigate the consequences of a design basis event (DBE).
2. Spatial interaction – The effect(s) of nonsafety-related SSC failure on a safety-related component, such as pipe whip, jet impingement, general flooding, spray, and displacement/falling.
3. Structural interaction – Occurs in situations where a nonsafety-related piping system physically connects to a safety-related system and the nonsafety-related system is relied upon to provide physical support to the safety-related system up to and including an anchor.

The first item is addressed during the scoping process, by identifying the nonsafety-related systems and structures required to functionally support the accomplishment of a safety-related intended function under 10 CFR 54.4(a)(1) and then including these supporting systems and structures in scope of subsequent license renewal under 10 CFR 54.4(a)(2).

The remaining two items concern nonsafety-related SSCs with potential physical or spatial interaction with safety-related SSCs. Scoping of these SSCs is the subject of NEI 95-10, Appendix F, as referenced to in NEI 17-01. To ensure complete and consistent application of 10 CFR 54.4(a)(2) requirements and NEI 95-10, a technical basis document was prepared. The basis document includes a review of the CLB references relevant to physical or spatial interactions.

The basis document describes the NMP1 approach to scoping of nonsafety-related systems with a potential for physical or spatial interaction with safety-related SSCs. The basis document provides appropriate 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 95-10. Additional detail on the application of the 10 CFR 54.4(a)(2) scoping criterion is provided in Section 2.1.5.2.

2.1.3.4 **Scoping for Regulated Events**

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, and Station Blackout. The Commission's regulations for pressurized thermal shock are not applicable to the NMP1 boiling water reactor design. These basis documents are summarized as follows:

Fire Protection

Systems and structures relied on in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48) are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3) requirements (Reference 1.7.7).

The fire protection technical basis document identified those systems and structures required for the fire protection program to comply with the fire protection requirements of 10 CFR 50.48 and associated NMP1 commitments. This includes systems and structures required to support the various analyses related to the NFPA 805 transition as follows:

- Fire Protection Fundamentals and Design Elements – review of classical fire protection systems and features (e.g., detection, suppression, fire pumps, barriers, combustible control, hot work control, etc.).
- Nuclear Safety Capability Assessment (NSCA) – verify that NMP1 could safely bring the plant to a safe and stable shutdown given a fire anywhere in the plant or in the yard.
- Fire Probabilistic Risk Assessment (PRA) – verify a fire anywhere in the plant would not result in a core damage frequency (CDF) or large early release frequency (LERF) value in excess of the regulatory criteria.
- Non-Power Operations (NPO) – determine the most impactful areas in the plant during an outage and institute additional fire protection measures in those areas during high risk evolutions.
- Radiation Release – verify that a release of radioactivity resulting from firefighting activities will not exceed 10 CFR 20 limits.

Most components at NMP1 are associated with a system or structure through design drawings and reflected in the NMP1 component database. License renewal scoping is performed at the system and structure level. The scope of individual components is not within the scope of the fire protection technical basis document. Individual components or pieces of equipment are identified only when a system or structure correlation does not exist or when appropriate in determining system boundaries.

The fire detection and suppression systems at NMP1 are plant-wide systems that protect a wide variety of plant equipment. Not all portions of the various fire protection systems are required to demonstrate compliance with NFPA 805 and are therefore not included in the scope of license renewal. Therefore, the structures that are only associated with the excluded portions of NFPA 805 credited systems are not included in the scope of license renewal.

Environmental Qualification

Criterion 10 CFR 54.4(a)(3) requires that 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 environmental qualification (10 CFR 50.49) be included within the scope of subsequent license renewal (Reference 1.7.8).

The NMP1 Environmental Qualification (EQ) program includes 1) safety-related electrical equipment, 2) nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions, and 3) certain post-accident monitoring equipment, as defined in 10 CFR 50.49(b)(1), 10 CFR 50.49(b)(2), and 10 CFR 50.49(b)(3), respectively. This equipment is included within the scope of subsequent license renewal.

The environmental qualification basis document summarizes the results of a review of NMP1 EQ program documents. The EQ basis document provides a list of systems that include EQ components. The EQ basis document also provides a list of structures that provide the physical boundaries for the postulated harsh environments and contain environmentally qualified electrical equipment. These systems and structures are 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 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 anticipated transients without scram (10 CFR 50.62) be included within the scope of subsequent license renewal (Reference 1.7.9).

An Anticipated Transient Without Scram (ATWS) is an anticipated operational occurrence that generates an automatic scram signal, accompanied by a failure of the reactor protection system to automatically shut down the reactor. The 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 shut down the reactor, and to mitigate the consequences of an ATWS event. NMP1 is a boiling water reactor (BWR). For BWRs, the following requirements apply:

1. Each BWR must have an alternate rod injection (ARI) system with redundant scram air header exhaust valves. The ARI system must be independent of the existing reactor trip system.
2. Each BWR must have a standby liquid control system with defined boron injection capabilities. Standby liquid control system automatic initiation is not

required for plants issued a construction permit before July 26, 1984, unless already installed.

3. Each BWR must have equipment to trip the recirculation pumps automatically under conditions indicative of an ATWS.

The ATWS basis document summarizes the results of a review of the NMP1 current licensing basis with respect to ATWS. The NMP1 design features to meet the requirements of 10 CFR 50.62 for ATWS mitigation include:

- Alternate Rod Insertion (ARI) system features to satisfy the requirements of 10 CFR 50.62(c)(3). The ARI plant system is included in the Control Rod Drive subsequent license renewal system.
- Liquid Poison System to meet the requirements of 10 CFR 50.62(c)(4). The NMP1 Liquid Poison System is manually initiated.
- ATWS Recirculation Pump Trip (RPT) system to satisfy the requirements of 10 CFR 50.62(c)(5). The ATWS-RPT function is included in the Reactor Coolant Pressure Boundary subsequent license renewal system.

The ATWS basis document provides a list of the systems required by 10 CFR 50.62 to reduce the risk from ATWS events. The basis document also provides a list of structures that provide physical support and protection for the ATWS systems. These systems and structures are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3) scoping criteria.

Station Blackout

Criterion 10 CFR 54.4(a)(3) requires that all systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for station blackout (10 CFR 50.63) be included within the scope of subsequent license renewal (Reference 1.7.10).

A station blackout (SBO) event is a complete loss of alternating current (AC) electric power to the essential and non-essential switchgear buses in a nuclear power plant (i.e., loss of the offsite electric power system concurrent with generator trip and unavailability of the onsite emergency AC power sources). SBO does not include the loss of available AC power to buses fed by station batteries through inverters or by alternate AC sources, nor does it assume a concurrent single failure or design basis accident. The SBO recovery path boundaries are shown in Figure 2.1-2.

NMP1 satisfies the requirement of 10 CFR 50.63 as a four-hour coping duration plant by closing all main steam isolation valves (MSIVs) and initiation of both emergency cooling trains. NMP1 capabilities, commitments, and analyses that demonstrate compliance with 10 CFR 50.63 are documented in UFSAR Chapter IX and in NRC safety evaluation reports and correspondence related to the SBO rule.

The NUREG-2192 guidance on scoping of equipment relied on to meet the requirements of the SBO rule (10 CFR 50.63) for subsequent license renewal has been incorporated into the NMP1 scoping methodology. In accordance with the

NUREG-2192 requirements, the SSCs required to cope with and recover from the SBO event are included within the scope of subsequent license renewal.

Coping with SBO

The NMP1 coping capability is independent of an alternative AC (AAC) power source for the coping period. The immediate actions to an SBO event are initiation of both emergency cooling trains and closing all MSIV's. These actions are adequate to provide the decay heat removal for at least four hours

Coping assessments were performed for:

1. Condensate Inventory for Decay Heat Removal
2. Class 1E Battery Capacity
3. Compressed Air
4. Effects of Loss of Ventilation
5. Containment Isolation
6. Reactor Coolant Inventory

Each coping assessment either demonstrated the ability to successfully cope with an SBO for the four-hour coping duration or recommendations were provided requesting additional analyses or confirmations.

Recovery from SBO

Recovery is defined as the repowering of the plant AC distribution system from offsite sources or onsite emergency AC sources. Recovery from an SBO event is accomplished via existing offsite and onsite power sources at NMP1. In alignment with the subsequent license renewal scoping methodology, for NMP1 station blackout, the boundary between the offsite transmission system and the plant electrical distribution system has been defined for each of the incoming offsite sources.

Onsite Power Sources

The onsite standby power source for the 4,160 V emergency safeguard buses are two emergency diesel generators.

In alignment with SBO scoping guidance provided in NUREG-2192 Section 2.5.2.1.1, the onsite standby power source meeting the requirements under 10 CFR 54.4(a)(1) (safety related systems) is included within the scope of license renewal.

Offsite Power Sources

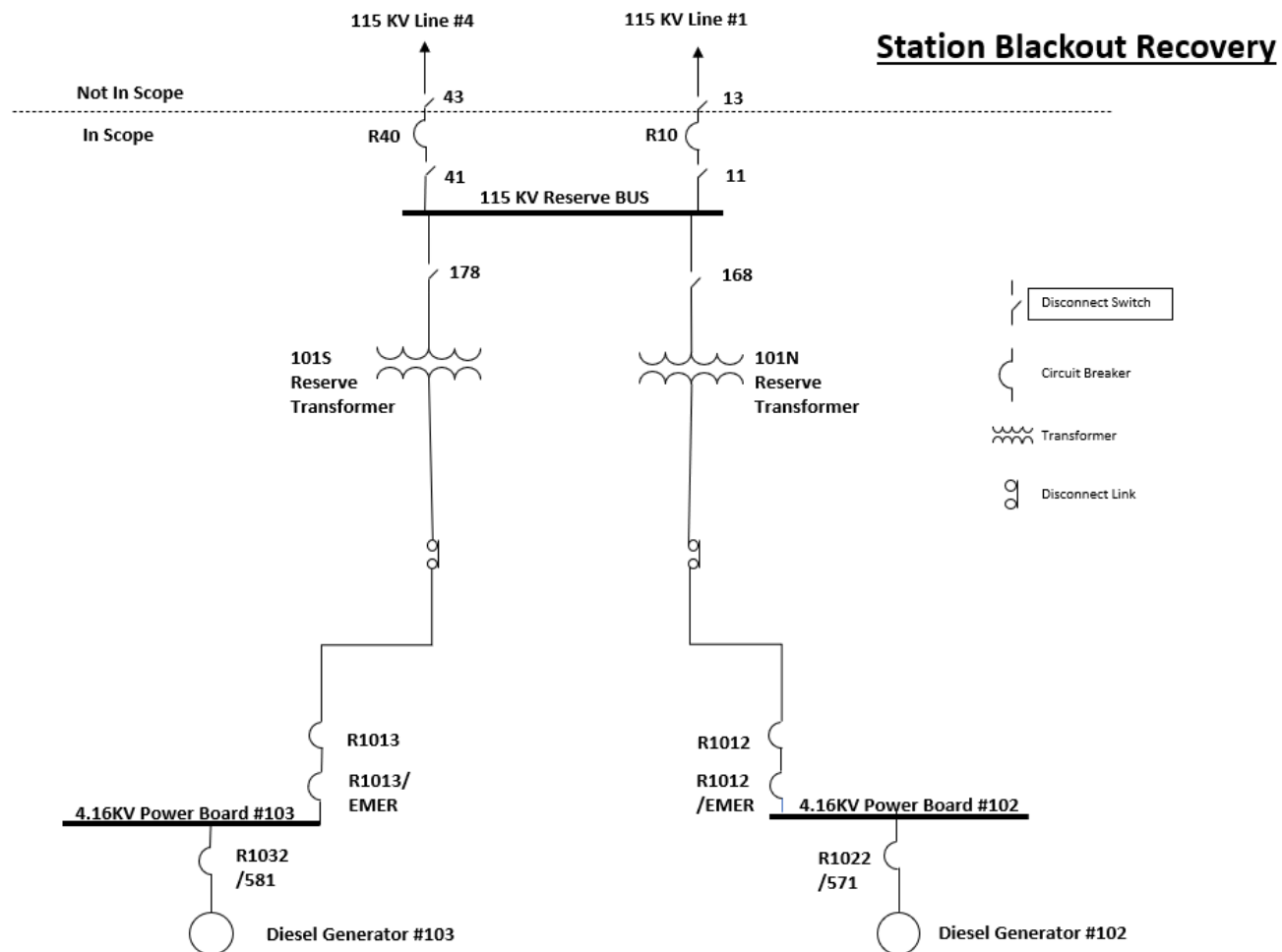
Offsite power is supplied to two separate 115KV lines from the transmission network. One line is from the South Oswego Steam Station and the other line is from the Lighthouse Hill Station through the J. A. Fitzpatrick switchyard. These two offsite sources supply power for station startup, and act as the reserve supply to the auxiliaries, and the normal supply to selected auxiliaries. Each line is

protected by a 115 KV, 1,200 amp, three-phase, 5,000 KVA oil circuit breaker designed to trip on specified trip conditions. Downstream of the breakers, both lines feed a common 115 KV reserve bus, that consequently connect to two independent reserve transformers. The two reserve transformers feed the 4,160 V emergency safeguard buses. The two independent reserve transformers also serve as the preferred power and alternate sources to a nonsafety-related 4,160 V bus.

In alignment with SBO scoping guidance provided in NUREG-2192 Section 2.5.2.1.1, the plant system portion of the offsite power system that is used to connect the plant to the offsite power source meeting the requirements under 10 CFR 54.4(a)(3) is included within the scope of license renewal. This path includes the switchyard circuit breakers, disconnect switches, 115KV reserve bus, and the reserve transformers used to power the onsite electrical distribution system and the associated control circuits.

The SBO basis document summarizes the results of a review of the NMP1 current licensing basis with respect to station blackout. The basis document provides lists of systems and structures credited in NMP1 SBO evaluations. For the listed systems and structures, the basis document also identifies appropriate CLB references. These systems and structures are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3) scoping criteria.

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2.1.4 INTERIM STAFF GUIDANCE DISCUSSION

The NRC has encouraged applicants for subsequent license renewal to address Subsequent License Renewal - Interim Staff Guidance (SLR-ISG) issues in subsequent license renewal applications. All SLR-ISGs have been incorporated in NUREG-2191, Revision 1 and NUREG-2192, Revision 1 as of November 2025.

2.1.5 SCOPING PROCEDURE

The scoping process is the systematic approach used to identify the NMP1 systems, structures, and components within the scope of subsequent license renewal. 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 functions and intended functions were identified from a review of the source CLB documents. In scope boundaries were established and documented in the system and structure scoping reports, 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 2.1.6. The system and structure scoping results are provided in Section 2.2.

The NMP1 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 System
- Structures and Component Supports
- Electrical Systems

Each NMP1 system and structure was then scoped for subsequent license renewal using the criteria of 10 CFR 54.4(a). These criteria are briefly identified as follows:

- Title 10 CFR 54.4(a)(1) – Safety-Related
- Title 10 CFR 54.4(a)(2) – Nonsafety-Related affecting safety-related
- Title 10 CFR 54.4(a)(3) – Regulated Events:
 - Fire Protection (10 CFR 50.48)
 - Environmental Qualification, EQ (10 CFR 50.49)
 - Pressurized Thermal Shock (10 CFR 50.61) (PWRs only)
 - Anticipated Transient Without Scram, ATWS (10 CFR 50.62)
 - Station Blackout, SBO (10 CFR 50.63)

The application of each of these criteria is discussed in Section 2.1.5.1, Section 2.1.5.2, and Section 2.1.5.3 below:

2.1.5.1 **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 shutdown 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 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable.*

At NMP1, the safety-related plant components are identified in controlled engineering drawings and in the component database. The safety-related classifications in the NMP1 component database were populated using a controlled procedure, with classification criteria consistent with the above 10 CFR 54.4(a)(1) criteria. The classification criteria differences have been evaluated in a subsequent license renewal basis document as described in Section 2.1.3.2 and accounted for during the subsequent license renewal scoping process.

Safety-related classifications for systems and structures are based on system and structure descriptions and analyses in the UFSAR or on design basis documents such as engineering drawings, design specifications, 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. The component database listing of safety-related components was also reviewed to identify the systems and structures included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1) criteria. The review also confirmed that all plant conditions, including conditions of normal operation, anticipated operational occurrences, design basis accidents, external events, and natural phenomena as described in the CLB, were considered for subsequent license renewal scoping.

2.1.5.2 **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:

All 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 three categories is discussed as follows:

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

This category addresses nonsafety-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. SSCs required to perform a function to support a safety function are generally classified as safety-related and are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). For the exceptions where nonsafety-related SSCs are required to remain functional to support a safety function, the function is listed as a 10 CFR 54.4(a)(2) intended function, and the SSC is included in scope. The nonsafety-related SSCs that were included within the scope of subsequent license renewal to functionally 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 green. Nonsafety-related SSCs that support safety functions were determined by review of the following documents:

- UFSAR
- Controlled plant component database
- Maintenance Rule database
- Engineering drawings and calculations
- Other licensing basis documentation such as licensing correspondence and NRC Safety Evaluation Reports

As an additional confirmation of scoping to meet 10 CFR 54.4(a)(2) criteria, a supporting system review was completed as part of the scoping process. The scoping process was performed on a system 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, which support the system functions. Nonsafety-related supporting systems required to support a 10 CFR 54.4(a)(1) function identified through this review were included in scope with the support function identified as a 10 CFR 54.4(a)(2) intended function for subsequent license renewal. Nonsafety-related mechanical systems, or nonsafety-related portions of safety-related systems credited in CLB documents to support a safety-related function have been included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2) and are described in Section 2.3.

The next two 10 CFR 54.4(a)(2) scoping categories are the subject of NEI 95-10, Appendix F, as referenced to in NEI 17-01. The guidance requires that, when demonstrating that 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 provide support for safety-related SSCs, and those that are not directly connected to safety-related systems and have the potential for spatial interactions with safety-related SSCs. The methodology as described below for the identification of NMP1 SSCs that satisfy the 10 CFR 54.4(a)(2) scoping criterion was based on a review of applicable CLB documents, as well as plant-specific and industry operating experience.

Connected to and Provide Structural Support for Safety-Related SSCs

For nonsafety-related SSCs directly connected to safety-related SSCs the nonsafety-related piping and supports, up to and including the first seismic or equivalent anchor (such as a series of at least two 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) beyond the safety/nonsafety interface, are within the scope of subsequent license renewal per 10 CFR 54.4(a)(2). The “first seismic or equivalent anchor” is defined such that the failure in the nonsafety-related pipe run beyond the first seismic or equivalent anchor will not render the safety-related portion of the piping unable to perform its intended function under CLB design conditions.

An alternative to specifically identifying a seismic anchor or equivalent anchor that supports the safety-related/nonsafety-related piping interface is to include enough of the nonsafety-related piping run to ensure these anchors are included and thereby ensure the piping and anchor intended functions are maintained. The intended function consists of two facets 1) providing structural support for the safety-related/nonsafety-related interface and 2) ensuring unacceptable nonsafety-related piping loads are not transferred through the safety-related/nonsafety-related interface. In accordance with NEI 95-10, Appendix F, as referred to in NEI 17-01, the following methods (a) through (f) were considered to define end points for the portion of nonsafety-related piping attached to safety-related piping to be included in the scope of subsequent license renewal. In these cases, the nonsafety-related piping was included in scope for 10 CFR 54.4(a)(2) up to one of the following:

- 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 license renewal scope includes the base-mounted component as it has a support function for the safety-related piping.
- b. A flexible connection that is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping system (i.e., does not support loads or transfer loads across it to connecting piping).
- c. A free end of nonsafety-related piping, such as a drain pipe that ends at an open floor drain.
- d. For nonsafety-related piping runs that are connected at both ends to safety-related piping, the entire run of nonsafety-related piping is included in scope.
- e. A point where buried piping exits the ground. The buried portion of the piping should be included in the scope of license renewal. A determination that the buried piping is well founded on compacted soil that is not susceptible to liquefaction must be documented.

- 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, because significantly smaller piping does not impose loads on larger piping and does not support larger piping. The moment of inertia ratio used was 25 to 1.

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

Failure in the 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 red. Symbols identifying the anchor locations and the seismic analysis boundaries that define the structural support boundary for safety-related piping systems are shown on the subsequent license renewal boundary drawings in blue. 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 evaluated for subsequent license renewal scope in accordance with 10 CFR 54.4(a)(2) requirements. 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. Plant walkdowns were performed, as required, to confirm that all structures containing safety-related SSCs were identified.

As described in NEI 95-10, Appendix F, as referenced in NEI 17-01, there are two options when performing this scoping evaluation: a mitigative option and a preventive option.

Mitigative Option: The mitigative option involves crediting plant mitigative features to protect safety-related SSCs from failures of nonsafety-related SSCs. Plant mitigative features considered include pipe whip restraints, jet impingement shields, spray and drip shields, seismic supports, flood barriers, and physical barriers (e.g., floors, walls, doors, conduit). 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. Where possible, mitigative features were used to prevent spatial interaction between safety-related SSCs and nonsafety-related SSCs. No credit was taken for separation by distance alone without a mitigative feature capable of preventing the spatial interaction. The mitigative features were included in the scope of subsequent license renewal.

Preventive Option: The preventive option involves identifying the nonsafety-related SSCs that have a spatial relationship such that failure could adversely impact the performance of a safety-related SSC intended function and including the identified nonsafety-related SSC within the scope of subsequent license renewal without consideration of plant mitigative features. The preventive option was used for scoping nonsafety-related systems containing water, steam, or oil utilizing a “spaces” approach. The boundaries for the “spaces” are entire structures, or in limited cases rooms within a structure, that are defined by physical barriers separating vulnerable safety-related targets from nonsafety-related hazards. The structures of concern for potential spatial interaction were identified based on a review of the CLB to determine which structures contained vulnerable safety-related SSCs. Plant walkdowns were performed, as required, to confirm that all structures containing safety-related SSCs were identified.

Nonsafety-related piping and components that contain water, oil, or steam, and are located inside structures that contain safety-related SSCs, are included in scope for potential spatial interaction under criterion 10 CFR 54.4(a)(2), unless it can be demonstrated that age-related failure of the nonsafety-related SSC cannot prevent accomplishment of a safety-related SSC’s safety function. This can be achieved by either confirming that there is no credible failure of the nonsafety-related SSC that would result in spatial interaction with safety-related SSCs or by demonstrating that the safety-related target SSC is not vulnerable to failure resulting from spatial interaction with failed nonsafety-related hazard SSCs in the area.

The physical configuration of station SSCs provides the basis for demonstrating that spatial interaction with safety-related SSCs is not credible. Typically, this is demonstrated by verifying adequate physical barriers exist separating nonsafety-related hazards from safety-related targets, thereby preventing the potential for spatial interaction. For non-pressurized systems (e.g., drain systems), the configuration and location of the system with respect to safety-related SSCs in the area can be considered to determine if spatial interaction is credible. Spatial interaction with safety-related SSCs is not credible for non-pressurized systems unless safety-related SSCs are located physically below the non-pressurized components. No credit was taken for separation by distance alone to exclude nonsafety-related SSCs containing water, oil, or steam from the scope of subsequent license renewal.

The design of safety-related SSC and an evaluation of the specific hazards in the vicinity of the safety-related SSC provides the basis for demonstrating that the safety-related SSC is not vulnerable to failure resulting from spatial interaction. Safety-related SSCs that are fail-safe by design are not considered targets for spatial interaction provided that the failure of nonsafety-related SSCs would not prevent the safety-related SSC from attaining its fail-safe state. Safety-related SSCs that are qualified or designed for the environmental conditions the SSC would be exposed to following a postulated failure of nearby nonsafety-related SSCs are not considered targets for spatial interaction. To utilize this approach, the specific hazards in the area need to be considered, including exposure to potential aggressive chemicals that would be more limiting than the conditions for which the safety-related SSC was designed and dynamic effects like pipe whip that could occur due to failure of nonsafety-related SSCs in the area. Safety-related SSCs that are designed for submergence and robust SSCs (e.g., doors/hatches,

flood barriers, structural elements) are not vulnerable to failure due to spatial interaction unless there is the potential for exposure to aggressive chemicals or the potential for dynamic effects resulting from the failure of nearby nonsafety-related SSCs.

High-energy lines (normal operating service conditions above 200 degrees F and above 275 psig) with potential spatial interaction are included in the scope of subsequent license renewal under 10 CFR 54.4(a)(1) or (a)(2) depending on their safety classification. Safety-related high-energy lines are in scope under 10 CFR 54.4(a)(1), and nonsafety-related high-energy lines are in scope under 10 CFR 54.4(a)(2). Potential spatial interaction due to leakage or spray is assumed for moderate/low-energy liquid systems (normal operating service conditions less than or equal to 200 degrees F or less than or equal to 275 psig) for system pressure as low as atmospheric.

Air and gas systems (non-liquid) are not a hazard to other plant equipment and have therefore been determined not to have 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. As described in NEI 95-10, Appendix F, paragraph 5.2.2.2.2 for moderate/low energy liquid systems, physical impact from pipe whip or jet impingement do not occur and need not be considered. This same conclusion can be applied to systems containing air or gas. Thus, the nonsafety-related systems containing air or gas need not be included in the scope of subsequent license renewal for spatial interaction. The supports are included in scope to prevent the nonsafety-related piping from falling down and potentially impacting safety-related SSCs.

The piping systems included in the scope of subsequent license renewal under 10 CFR 54.4(a)(2) for potential spatial interaction with safety-related SSCs are identified on the subsequent license renewal boundary drawings in red.

Scoping of Abandoned Equipment

Abandoned equipment is not included within the scope of subsequent license renewal if it has been confirmed to be isolated (cut/capped), vented, and drained. If this confirmation cannot be made, the system or portions thereof, are included within the scope of subsequent license renewal for aging management if there is the potential for 10 CFR 54.4(a)(2) spatial or structural interaction. Abandoned equipment is not relied on to perform any function delineated in 10 CFR 54.4(a)(1) or (a)(3) as it is nonoperational. However, failure of abandoned equipment could potentially impact the performance of the safety-related function of surrounding equipment if the abandoned equipment contains water, steam, or oil. If the abandoned equipment excluded from scope has been vented, fluids drained, and isolated (cut/capped), this equipment does not perform a 10 CFR 54.4(a)(2) intended function for subsequent license renewal. In addition, disconnection of wiring for power, control, or parameter indication and air supplies is not necessary to ensure that the abandoned equipment has no potential spatial interaction with surrounding equipment.

2.1.5.3 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).

The regulation for pressurized thermal shock (10 CFR 50.61) is applicable to pressurized water reactors only, and therefore not applicable to NMP1 which is a boiling water reactor. For each of the other four regulations, a technical basis document was prepared to provide input into the scoping process. Each of the regulated event 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 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.

2.1.5.4 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) were standardized based on nuclear safety criteria for boiling water reactors as documented in industry standard ANSI/ANS-52.1-1983. The use of standardized 10 CFR 54.4(a)(1) functions provided 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 2.1.6.2.

2.1.5.5 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 process for evaluating mechanical systems is different from the process for structures, 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 physical 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 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 required to perform or support a safety-related function, or a function that demonstrates compliance with one of the subsequent license renewal regulated events, are identified on the system piping and instrumentation diagrams by green lines. 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 red lines. A computer sort and download of associated system components from the component 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 support the intended functions are included in 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 design basis documentation. Plant walkdowns were performed when required for additional confirmation. Structural bolting required to support the structure proper is evaluated with the structure. Structural bolting supporting the intended function of a component support or structural commodity component is evaluated with the component support or structural commodity component. A site plan layout drawing is marked up to create a subsequent license renewal boundary drawing showing the structures within the scope of subsequent license renewal. Structures included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1) are identified in green. Structures included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2) or (a)(3) are identified in red.

Electrical Systems

Electrical and I&C systems, and electrical components within mechanical systems, did not require further system evaluations to determine which components were required to perform or support the identified intended functions. A bounding scoping approach is used for electrical equipment. All electrical components within in scope systems were included within the scope of subsequent license renewal. In scope electrical components were placed into commodity groups and were evaluated as commodities during the screening process as described in Section 2.1.6.

2.1.6 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.

2.1.6.1 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:

Each application must contain the following information:

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

- (1) For those systems, 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 that are subject to aging management review.

NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" and NEI 95-10, Appendix B, were used as the basis for the identification of passive structures and components. Most passive

structures and components are long-lived. In the few cases where a passive component is determined not to be long-lived, such determination is documented in the screening evaluation and, if applicable, on the associated subsequent license renewal boundary drawing.

The NMP1 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 completed scoping packages include written descriptions and marked up system piping and instrumentation diagrams that clearly identify the in scope system boundary 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. Component listings from the component database were also reviewed to confirm that all system components were considered. 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. Mechanical components are screened with the system in which they were scoped.

Some mechanical components, when combined, are considered a complex assembly. 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. An example of a complex assembly are the diesel generators. 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 scoping and screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants."

Structures

The structure screening process also began with the results from the scoping process. For in scope structures, the completed scoping packages include written descriptions of the structure. If only selected portions of the structure are in scope, the in scope portions are described in the scoping evaluation. The associated structure drawings were reviewed to identify the passive, long-lived structures and components, structure types, and component types. Plant walkdowns were performed when required for confirmation.

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.

Electrical and I&C components for the in scope systems were assigned to commodity groups based on the listings in NUREG-2192, Table 2.1-6. The commodities subject to an aging management review are identified by applying the criteria of 10 CFR 54.21(a)(1). 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 and commodities are active.

Electrical and I&C components such as resistance temperature detectors (RTDs), sensors, thermocouples, and transducers as well as electric heaters primarily serve an electrical function; however, they can also serve a mechanical pressure boundary function. According to Appendix B of NEI 95-10, the electrical portions of these components are active per 10 CFR 54.21(a)(1)(i) and are therefore not subject to aging management review. Only the pressure boundary of such an in scope component is subject to aging management review.

The sequence of steps and special considerations for identification of electrical commodities that require an aging management review is as follows:

1. Electrical and I&C components and commodities in systems within the scope of subsequent license renewal at NMP1 were identified and listed. The listing provided by NUREG-2192, Table 2.1-6, is the basis for this list. Electrical and I&C components and commodities were organized into groups such as circuit breakers, switches, and cables. Individual specific components were not identified. The electrical commodities were identified from a review of plant documents, controlled drawings, the component database, and interface with the parallel mechanical screening efforts.
2. Following the identification of the electrical commodities, the criterion of 10 CFR 54.21(a)(1)(i) was applied to identify commodities that perform their functions without moving parts or without a change in configuration or properties (referred to as "passive" components).
3. The passive electrical commodities were reviewed to determine if the commodity performs a subsequent license renewal intended function. If an electrical commodity does not perform a subsequent license renewal intended function, it was not considered further and, therefore, is not subject to an aging management review.
4. The screening criterion found in 10 CFR 54.21(a)(1)(ii) excludes 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 10 CFR 54.21(a)(1)(ii) screening criterion was applied to those commodities that were not previously eliminated by the application of the 10 CFR 54.21(a)(1)(i) screening criterion. Components and commodities included in the plant environmental qualification (EQ) program are replaced on a specified interval based on a qualified life. Components and commodities in the EQ program do not meet the "long-lived" criterion of 10 CFR 54.21(a)(1)(ii) and are considered "short-lived" per the regulatory definition and are, therefore, not subject to an aging management review.

5. Components and commodities which support or interface with electrical components and commodities, for example, cable trays, conduits, instrument racks, panels and enclosures, are evaluated as structural components in Section 2.4.

The electrical commodities that require an aging management review are the separate electrical commodities that are not part of a larger active component.

The passive commodities that are not subject to replacement based on a qualified life or specified time period are subject to an aging management review. For NMP1, the electrical commodities that require an aging management review are identified in Section 2.5.

2.1.6.2 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. NMP1 has considered multiple intended functions where applicable, consistent with the staff guidance provided in Table 2.1-3 of NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants."

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

Table 2.1-1 Passive Structure and Component Intended Function Definitions

Passive Intended Function	Definition
Absorb Neutrons	Absorb neutrons.
Direct Flow	Provide spray shield or curbs for directing flow, which may include protective features for medium energy line breaks (MELB). Also applies to diffusers credited for fluid diffusion/dissipation, e.g., HVAC diffusers.
Electrical Continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.
Expansion/Separation	Provide for thermal expansion and/or seismic separation.
Filter	Provide filtration or foreign material exclusion.
Fire Barrier	Provide rated fire barrier to confine or retard fire from spreading to or from adjacent areas of the plant.
Flood Barrier	Provide flood protection barrier (internal and external flood event). This may include protective features for medium energy line breaks (MELB).
Gaseous Release Path	Provide path for release of filtered and unfiltered gaseous discharge.
Heat Transfer	Provide heat transfer.
HELB/MELB Shielding	Provide shielding against high energy line breaks (HELB), and protective features for medium energy line breaks (MELB).
Insulate (Electrical)	Insulate and support an electric conductor.
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 the required structural integrity when the nonsafety-related leakage boundary piping is also attached to safety-related piping.
Maintain Adhesion	Provides adhesion to the substrate.
Mechanical Closure	Provide closure of components. Typically used with bolting.
Missile Barrier	Provide missile barrier (internal or external missiles).

Table 2.1-1 Passive Structure and Component Intended Function Definitions

Passive Intended Function	Definition
Pressure Boundary	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered, or provide fission product barrier for containment pressure boundary, or provide containment isolation for fission product retention, or provide the containment, holdup and plateout function (for Main Steam system). This function includes the required leakage boundary function to prevent spatial interactions that could cause failure of safety related SSCs.
Pressure Relief	Provide overpressure protection.
Shelter/Protection	Provide shelter/protection to safety-related components.
Shielding	Provide shielding against radiation.
Spray	Convert fluid into spray. This function includes the required pressure boundary function to ensure sufficient flow is delivered at an adequate pressure.
Structural Integrity (Attached)	Nonsafety-related component that maintains mechanical and structural integrity to provide structural support to attached safety-related piping.
Structural Pressure Barrier	Provide pressure boundary or essentially leak tight barrier to protect public health and safety in the event of any postulated design basis events.
Structural Support	Provide structural support for structures and components within the scope for 10 CFR 54.4(a)(1), (a)(2), or (a)(3) or provide structural integrity to preclude nonsafety-related component interactions that could prevent satisfactory accomplishment of a safety-related function.
Structural Support to maintain core configuration and flow distribution	Provide structural support of fuel assemblies, control rods, and incore instrumentation, to maintain core configuration and flow distribution.
Thermal Insulation	Control of heat loss to preclude overheating of nearby safety-related SSCs.
Thermal Insulation Jacket Integrity	Prevent moisture absorption and provide physical support of thermal insulation.
Throttle	Provide flow restriction.
Water Retaining Boundary	Provide an essentially leak-tight boundary.

2.1.6.3 **Stored Equipment**

Equipment that is stored on site for installation or used in achieving safe and stable shutdown during any mode of operation is considered to be within the scope of subsequent license renewal. Stored equipment may also be used as directed by emergency operating procedures and damage repair procedures. Periodic surveillances are performed to verify that the equipment and materials are at the designated location, in the quantity specified, and in good condition and capable of performing the intended function. The periodic inspections are implemented by controlled NMP1 procedures. The stored equipment is subject to replacement based on requirements implemented by controlled procedures and is therefore not long-lived and not subject to an aging management review. Tools and supplies used to place the stored equipment in service are not within the scope of subsequent license renewal.

2.1.6.4 **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 groups for the purpose of subsequent license renewal: (a) packing, gaskets, component seals, and O-rings; (b) structural sealants; (c) oil, grease, and component 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, NMP1 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.
- Group (b) structural sealants: AMRs 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 AMR.
- Group (d) consumables (system filters, fire extinguishers, fire hoses, and air packs): System ventilation filters are replaced in accordance with plant procedures based on vendor manufacturers' requirements and system testing. Fire extinguishers, self-contained breathing air packs and fire hoses are within the scope of subsequent license renewal but are not subject to aging management because they are replaced based on condition. These components are periodically inspected in accordance with NFPA 10 for portable fire extinguishers, ANSI Z88.2-1992 for self-contained breathing air packs, and NFPA 1962 for fire hoses. These require replacement of

equipment based on their condition or performance during testing and inspection. The periodic inspections are implemented by controlled NMP1 procedures. These components are subject to replacement based on requirements implemented by controlled procedures and are therefore not long-lived and not subject to an aging management review.

2.1.7 GENERIC SAFETY ISSUES

In accordance with the guidance in NEI 17-01 and Appendix A.3 of NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," review of NRC generic safety issues (GSIs) as part of the subsequent license renewal process is required to satisfy 10 CFR 54.29. This guidance suggests that GSIs involving issues related to subsequent license renewal aging management reviews or time-limited aging analyses (TLAAs) should be addressed in the subsequent license renewal application. Based on Nuclear Energy Institute (NEI) and NRC guidance, NUREG-0933 "Resolution of Generic Safety Issues," Supplement 35 (Reference 1.7.15), and more recent NRC Generic Issue Management Control System Reports, the following GSIs are addressed for NMP1 subsequent license renewal:

- 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 analyses, including typical crane-related TLAAs such as cyclic loading analyses. This issue is now closed. (ADAMS Accession No. ML113050589)
- GSI-189, Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Combustion During a Severe Accident - This issue is not applicable to NMP1. NMP1 does not have Ice Condenser or Mark III Containments. NMP1 has Mark I Primary Containments. This issue is now closed.
- GSI-191, Assessment of Debris Accumulation on PWR Sump Performance - This issue is not applicable to NMP1. NMP1 is a BWR.
- GSI-193, BWR ECCS Suction Concerns - The Generic Issues Review Panel completed an assessment and found this issue does not present a significant safety hazard. No further regulatory actions are required. This issue is now closed. (ADAMS Accession No. ML16082A288)
- GSI-199, Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States for Existing Plants - 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. The NRC staff confirmed that the licensee adequately addressed the reevaluated seismic hazard within NMP1's mitigation strategies for beyond-design-basis external events. (ADAMS Accession No. ML17066A435)

- 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. (ADAMS Accession No. ML20260H122)

Therefore, there are no GSIs involving issues related to aging management reviews or TLAAAs that need to be addressed as part of the NMP1 subsequent license renewal application.

2.1.8 CONCLUSION

The scoping and screening methodology described above was used for the NMP1 IPA to identify the systems, structures, and components that are within the scope of subsequent license renewal and that are subject to an aging management review. The methodology is consistent with and satisfies 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 Nine Mile Point Nuclear Station, Unit 1 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 system, structure, and commodity group in the Table.

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Reactor Vessel, Internals, and Reactor Coolant System		
Control Rod Drive System	Yes	2.3.1.1
Reactor Coolant Pressure Boundary System	Yes	2.3.1.2
Reactor Pressure Vessel	Yes	2.3.1.3
Reactor Pressure Vessel Instrumentation System	Yes	2.3.1.4
Reactor Pressure Vessel Internals	Yes	2.3.1.5
Reactor Recirculation System	Yes	2.3.1.6
Engineered Safety Features		
Containment Spray System	Yes	2.3.2.1
Core Spray System	Yes	2.3.2.2
Emergency Cooling System	Yes	2.3.2.3
Auxiliary Systems		
Administration Building HVAC System	No	UFSAR III.E.1.1.4, III.E.1.2.2
Circulating Water System	Yes	2.3.3.1
City Water System	Yes	2.3.3.2
Compressed Air Systems	Yes	2.3.3.3
Containment Systems	Yes	2.3.3.4
Control Room HVAC System	Yes	2.3.3.5
Cranes, Hoists, and Refueling Equipment System	Yes	2.3.3.6
Electric Steam Boiler System	Yes	2.3.3.7
Emergency Diesel Generator System	Yes	2.3.3.8
Fire Detection and Protection System	Yes	2.3.3.9
Hydrogen Water Chemistry System	No	UFSAR X.M.1.2, X.M.2.2
Laboratory Systems	No	UFSAR XII.A.1.2.2, XII.A.2.2.1, XII.B.3.1.1
Liquid Poison System	Yes	2.3.3.10
Makeup Demineralizer System	Yes	2.3.3.11
Radioactive Waste System	Yes	2.3.3.12
Radwaste Solidification & Storage Building HVAC System	No	UFSAR III.I.1.4, III.I.2.2
Reactor Building Closed Loop Cooling System	Yes	2.3.3.13
Reactor Building HVAC System	Yes	2.3.3.14
Reactor Water Cleanup	Yes	2.3.3.15
Sampling System	Yes	2.3.3.16
Sanitary Sewerage System	No	UFSAR III.E.2.2.1
Screen and Pump House Building HVAC System	No	UFSAR III.F.1.1.4

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Service Water System	Yes	2.3.3.17
Shutdown Cooling System	Yes	2.3.3.18
Spent Fuel Pool Cooling and Storage System	Yes	2.3.3.19
Turbine Building Closed Loop Cooling System	Yes	2.3.3.20
Turbine Building HVAC System	Yes	2.3.3.21
Waste Disposal Building HVAC System	No	UFSAR III.C.1.4, III.C.2.2
Steam and Power Conversion		
Condensate and Condensate Transfer System	Yes	2.3.4.1
Condenser Air Removal and Off-Gas System	Yes	2.3.4.2
Feedwater/High Pressure Coolant Injection System	Yes	2.3.4.3
Main Generator and Auxiliary System	Yes	2.3.4.4
Main Steam System	Yes	2.3.4.5
Main Turbine and Auxiliary System	Yes	2.3.4.6
Structures and Component Supports		
Component Supports Commodity	Yes	2.4.1
Miscellaneous Not-In-Scope Structures	No	Comment 1; UFSAR II.A.3, III.C, III.E.1, III.E.2, III.E.3, III.H, III.J, XVI.D.1.0
Primary Containment	Yes	2.4.2
Reactor Building	Yes	2.4.3
Screen and Pump House Building	Yes	2.4.4
Structural Commodity Group	Yes	2.4.5
Turbine, Waste Handling, and Admin. Structures	Yes	2.4.6
Yard Structures	Yes	2.4.7
Electrical Systems		
115KV & 345KV AC Electrical Distribution System	Yes	UFSAR IX.B.1.1, IX.B.1.2
120V AC Electrical Distribution System	Yes	UFSAR IX.B.2.2, IX.B.2.3, IX.B.2.4, IX.B.2.5
125V DC Electrical Distribution System	Yes	UFSAR IX.B.4.2, IX.B.4.3
24V DC Electrical Distribution System	No	UFSAR IX.B.2.1
480V, 600V, and 4.16KV AC Electrical Distribution System	Yes	UFSAR IX.A, IX.B.1.2, IX.B.2, XV.B.3.25
Anticipated Transient Without Scram System	Yes	UFSAR VIII.A.1.2, VIII.A.2.2, X.C.2.8, X.C.3.5
Area & Process Radiation Monitoring System	Yes	UFSAR XII.B.2.0, VIII.C.3, Table VIII-4

Table 2.2-1 Plant Level Scoping Results

System, Structure or Commodity Group	In Scope for License Renewal?	Reference
Communications System	Yes	UFSAR XII.B.2.1, XII.B.2.2
Miscellaneous Electrical Components	Yes	UFSAR VII.A.1, VII.A.2, VII.A.3, VII.B.3, VIII.A.3, XV
Neutron Monitoring System	Yes	UFSAR VIII.A.2.1, VIII.C.1.0, VIII.C.1.1.5, VIII.C.1.2, VIII.C.1.2.1, VIII.C.1.2.2, VIII.C.1.2.3, XV.C.3.1.4
Plant Computer Systems	Yes	UFSAR VIII.A.1.1, VIII.C.1.1.3, VIII.C.1.1.4, VIII.C.1.2.4, VIII.C.4.1, VIII.C.5.4, VIII.C.5.5, VIII.C.5.6.5, VIII.C.5.6.8, Table VIII-2, Table VIII-3, Figure VIII-29, IX.A.2.5, XVIII.B.2
Plant Lighting System	Yes	UFSAR III.B.3, IX.B.4.2
Reactivity Control System	No	UFSAR I.A.4.3, I.A.6.2, IV.B.6, VII.D, VIII.C.4.1, Figure VIII-29, XV.C.4
Reactor Protection System	Yes	UFSAR I.A.6.3, III.B.2.2, IV.B.6.2.2, VIII.A.1.1, Figure VIII-2, IX.B.2, XV.B.3, XV.C
Remote Shutdown System	Yes	UFSAR X.L

Comments:

1. The Miscellaneous Not-In-Scope Structures are non-safety-related and provide support, shelter, and protection for personnel, stored materials, or non-safety-related systems, structures, and components (SSCs) that do not perform an intended function for license renewal. These non-safety-related structures are also separated from safety-related systems, structures, and components such that the structures' failure would not impact a safety-related function.

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL

2.3.1 REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

The following systems are addressed in this section:

- Control Rod Drive System (2.3.1.1)
- Reactor Coolant Pressure Boundary System (2.3.1.2)
- Reactor Pressure Vessel (2.3.1.3)
- Reactor Pressure Vessel Instrumentation System (2.3.1.4)
- Reactor Pressure Vessel Internals (2.3.1.5)
- Reactor Recirculation System (2.3.1.6)

2.3.1.1 **Control Rod Drive System**

Description

The Control Rod Drive (CRD) System is a reactivity control system that utilizes pressurized reactor grade water to position neutron absorbing control rods within the reactor core. The primary safety-related purpose of the CRD System is to support rapid insertion of negative reactivity into the reactor core to shut down the reactor under accident or transient conditions by simultaneously inserting all control rods. The CRD System is also used to manage core reactivity and control reactor power during normal reactor operation by inserting or withdrawing control rods at a controlled rate, one rod at a time. The CRD System accomplishes these functions by providing water at the required operating pressures to the control rod drive mechanisms in response to inputs from the reactor protection system and the reactor manual control system. The CRD System includes the alternate rod insertion (ARI) system, which provides an alternate means of venting the scram air header and inserting control rods that is independent of the reactor protection system. The ARI function serves to mitigate the consequences of an Anticipated Transient without Scram (ATWS) event and may be initiated automatically or manually.

The CRD System also supplies a source of cool, clean, high-pressure water to the reactor pressure vessel, to the reactor vessel level instrumentation reference leg backfill system, and to the keep-full system for the emergency cooling system.

The CRD System process lines passing through Primary Containment are provided with primary containment isolation valves. Class I portions of the system are included in the Reactor Coolant Pressure Boundary System.

Intended Functions

1. Introduce negative reactivity to achieve or maintain subcritical reactor condition. The hydraulic control units (HCU) provide the motive force to the control rod drive mechanisms to rapidly insert control rods during a scram event. The scram discharge volume provides a low-pressure sink for water discharged from the above piston area of control rod drive mechanisms during a scram event. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The scram discharge volume includes level instrumentation that causes actuation of the reactor protection system upon a high scram dump volume water level condition. 10 CFR 54.4(a)(1)
3. Provide primary containment. The CRD System includes safety-related containment penetration associated with the CRD head spray line which has been abandoned. 10 CFR 54.4(a)(1)
4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Includes nonsafety-related SSCs that are functionally relied upon to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or (b) directly mitigate the consequences of a design basis event (DBE). The CRD System includes nonsafety-related components that provide for core cooling, directly into the core, during a small break LOCA.

10 CFR 54.4(a)(2)

5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The CRD System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in primary containment, the reactor building and the turbine building. 10 CFR 54.4(a)(2)
6. Relied upon 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). The CRD System includes equipment that is credited by Fire Safe Shutdown analysis to shutdown the reactor via the scram function and to provide inventory control through the operation of a CRD pump. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The CRD System includes instrumentation and equipment that is required to be environmentally qualified. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The CRD System includes solenoid valves that receive signals from the plant alternate rod insertion system to provide an alternate means of venting the scram air header and cause insertion of control rods. 10 CFR 54.4(a)(3)
9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The station blackout analysis credits the CRD System with successfully inserting all control rods upon receipt of scram initiation signals from the Reactor Protection System and provides water to the reactor during recovery. 10 CFR 54.4(a)(3)

UFSAR References

VIII.A.1
X.C.2.0
X.C.2.14
V.C.4.0
X.K

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001
SLR-NMP1-C18003C-001
SLR-NMP1-C18006C-001
SLR-NMP1-C18016C-001
SLR-NMP1-C18016C-002
SLR-NMP1-C18016C-003
SLR-NMP1-C18017C-001
SLR-NMP1-C18034C-002

**Table 2.3.1-1 Control Rod Drive System
Components Subject to Aging Management Review**

Component Type	Intended Function
Accumulator (Hydraulic Control Unit)	Pressure Boundary
Accumulator (Nitrogen Tank)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Gearbox	Pressure Boundary
Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Pump Gear Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Pump Gear Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Pump Gear Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Pump Gear Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)
Pump Casing (Control Rod Drive Pump)	Pressure Boundary
Rupture Disks	Pressure Boundary
Strainer (Element)	Filter
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)

The aging management review results for these components are provided in:

**Table 3.1.2-1 Control Rod Drive System
Summary of Aging Management Evaluation**

2.3.1.2 **Reactor Coolant Pressure Boundary System**

Description

The Reactor Coolant Pressure Boundary System (RCPB) includes those systems and components which contain or transport fluids to and from the reactor pressure vessel. The RCPB is defined as the reactor coolant system and all pressure-containing connections out to and including the outermost isolation valves. The RCPB consists of all those pressure-containing components such as pressure vessels, piping, pumps, and valves, that are:

- a. Part of the reactor coolant system, or
- b. Connected to the reactor coolant system, up to and including all of the following:
 1. The outermost containment isolation valve in system piping which penetrates the primary containment,
 2. The second of the two valves normally closed during normal reactor operation in system piping (such as vent and drain lines on the reactor recirculation system) which does not penetrate the primary containment; and
 3. The automatic depressurization system (ADS) electromatic relief valves (ERV) and reactor head safety valves.

The RCPB contains portions of other plant systems (e.g., Class I portion of feedwater/HPCI system). The RCPB only identifies system intended functions for those portions of the Class 1 system that provide flow paths or isolations. The interfacing SLR System retains all system functions and system intended functions for that system. RCPB provides flow-paths and isolations as needed for those interfacing systems to assure all functions are supported.

The reactor pressure vessel is also a part of the RCPB but is evaluated as a separate system called Reactor Pressure Vessel for SLR with system boundaries defined at the nozzle safe end to pipe welds. Therefore, the reactor head pressure safety relief valves are evaluated as a part of the RCPB.

The RCPB includes all ASME Section XI Class 1 components and sections of attached piping of the following license renewal systems:

- Emergency Cooling System
- Core Spray System
- Feedwater/High Pressure Coolant Injection System
- Main Steam System
- Reactor Water Cleanup System
- Reactor Recirculation System
- Liquid Poison System
- Control Rod Drive System
- Shutdown Cooling System
- Reactor Pressure Vessel Instrumentation System
- Sampling System

Intended Functions

1. Provide reactor coolant pressure boundary. The nuclear safety functions of the RCPB are (1) to prevent uncontrolled release of reactor coolant and radioactive material to primary containment, secondary containment and the turbine building main steam isolation valve (MSIV) room and provide geometry that ensures core cooling and (2) to provide system pressure relief. 10 CFR 54.4(a)(1)
2. Provide reactor coolant pressure boundary. The nuclear safety functions of the RCPB are to prevent uncontrolled release of reactor coolant and radioactive material to the environment. The main steam flow limiters are integral to the pressure boundary piping and have a permanently welded flow restricting venturi which is relied upon in main steam line break (MSLB) accident analyses to limit the loss of coolant from the primary system before closure of the MSIVs. The restrictors limit the coolant loss prior to closure of the isolation valves such that the resulting activity released to the environs can be tolerated. 10 CFR 54.4(a)(1)
3. Provide primary containment boundary. The RCPB contains radioactive material leakage or releases from equipment located within the primary containment. The RCPB maintains the primary containment boundary through the containment isolation valves. 10 CFR 54.4(a)(1)
4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The RCPB senses process conditions and generates signals for reactor trip and engineered safety features operation if process conditions exceed specified limits. Includes indication used for manual actuation of safety-related equipment. The RCPB includes instrumentation and process controls which provide signals for reactor trip and engineered safety features. 10 CFR 54.4(a)(1)
5. Supports interfacing SLR Systems by providing the necessary flow-paths and isolations, as required, to assure interfacing SLR Systems (a)(1) intended functions are met. 10 CFR 54.4(a)(1)
6. Relied upon 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). The RCPB provides the flow path for reactor coolant makeup and decay heat removal and maintains the reactor coolant pressure boundary in support of reactor safe shutdown. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The RCPB includes systems that contain electrical equipment subject to the requirements of 10 CFR 50.49, the EQ rule. The RCPB also includes structures that provide the physical boundaries of the postulated harsh environments and contain environmentally qualified electrical equipment. The RCPB contains safety-related components located in areas with harsh environments and therefore have environmental qualifications. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The RCPB includes systems and

equipment to reduce the risk from ATWS. The RCPB components receive the recirculation pump trip signal and provides the flow path and maintains the pressure boundary for Liquid Poison injection. 10 CFR 54.4(a)(3)

9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The RCPB includes systems and equipment to cope with a complete loss of offsite and onsite power. The RCPB provides the flow path for reactor coolant makeup and decay heat removal and maintains the reactor coolant pressure boundary in support of reactor safe shutdown. 10 CFR 54.4(a)(3)

UFSAR References

V.A.2.0
V.B.1.4
V.B.3.0
V.B.5.0
V.D.3.3
V.D.3.4
V.E.3.3
VI.D
VI.D.2.0
VI Table VI-3a
VII.C.2.0
VIII.A.1.1
VIII.A.1.2
IX.B.6.2
X.K.2.2
XV.B

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001
SLR-NMP1-C18005C-002
SLR-NMP1-C18006C-001
SLR-NMP1-C18006C-002
SLR-NMP1-C18007C-001
SLR-NMP1-C18007C-002
SLR-NMP1-C18009C-001
SLR-NMP1-C18015C
SLR-NMP1-C18016C-001
SLR-NMP1-C18016C-003
SLR-NMP1-C18017C-001
SLR-NMP1-C18017C-002
SLR-NMP1-C18018C-001
SLR-NMP1-C18019C
SLR-NMP1-C18020C
SLR-NMP1-C18041C-001
SLR-NMP1-C18041C-002
SLR-NMP1-C18041C-007

**Table 2.3.1-2 Reactor Coolant Pressure Boundary System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Class 1)	Mechanical Closure
Flow Device (Class 1)	Pressure Boundary
	Throttle
Piping and piping components with reflective metal insulation	Pressure Boundary
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary
Pump Casing (Reactor Recirculation)	Pressure Boundary
Valve Body: Class 1	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.1.2-2 Reactor Coolant Pressure Boundary System
Summary of Aging Management Evaluation**

2.3.1.3 **Reactor Pressure Vessel**

Description

The Reactor Pressure Vessel (RPV) is designed to contain and support the reactor core, reactor internals, and the reactor coolant-moderator. The RPV serves as a barrier against leakage of radioactive materials to the drywell and the release of fission products to the environment.

The RPV is a vertical, cylindrical pressure vessel with hemispherical heads. The cylindrical shell and hemispherical heads are fabricated from low alloy carbon steel that is clad on the interior with stainless steel weld overlay. The top head is secured to the vessel with studs and nuts and includes two concentric seal-rings between the vessel head flange and the vessel flange to prevent reactor coolant leakage. The top head leak detection line taps off of the vessel head between the seal rings to detect leakage should the inner seal-ring fail. The top head also includes nine safety valves that prevent over-pressurization of the RPV. The vessel shell and bottom head include penetration nozzles for the various systems that comprise the reactor coolant pressure boundary, including control rod drive housings and in-core instrumentation thimbles. The RPV nozzles for core spray, feedwater and the control rod drive (CRD) return line have thermal sleeves.

The RPV is supported by a steel skirt welded to the bottom head. The base of the skirt is continuously supported by a ring girder and sole plate fastened to a concrete foundation, which carries the load to the reactor building foundation slab.

The RPV boundaries for subsequent license renewal are at the vessel nozzle safe end-to-pipe welds including the CRD housings. As such, the top head penetrations are evaluated in the RPV and the nine attached safety valves are evaluated in the Reactor Coolant Pressure Boundary System (RCPB). Reactor internals are evaluated in the Reactor Pressure Vessel Internals System. Piping and instrumentation used to monitor RPV conditions are evaluated in the Reactor Pressure Vessel Instrumentation System however, the Class 1 portions of the Reactor Pressure Vessel Instrumentation System are evaluated in the RCPB.

Intended Functions

1. Provide reactor coolant pressure boundary. The reactor vessel forms a barrier against the release of reactor coolant and radioactive material to the primary containment. 10 CFR 54.4(a)(1)
2. Maintain reactor core assembly geometry. The nuclear safety function of the reactor vessel is to maintain reactor core assembly geometry for any event to ensure core cooling, core reactivity control, and the integrity of the fuel cladding as a radioactive material barrier. The reactor vessel provides support to the reactor vessel internals and maintains a floodable volume within the reactor. 10 CFR 54.4(a)(1)
3. Provide structural support or restraint to SSCs in the scope of license renewal. The reactor vessel support skirt provides structural support for the reactor vessel. 10 CFR 54.4(a)(1)

4. Relied upon 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). The Reactor Pressure Vessel provides the flow path for core cooling and maintains the reactor coolant pressure boundary for reactor safe shutdown. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Reactor Pressure Vessel provides the flow path for core cooling and maintains the reactor coolant pressure boundary for liquid poison injection. 10 CFR 54.4(a)(3)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Reactor Pressure Vessel provides the flow path for core cooling and maintains the reactor coolant pressure boundary for reactor safe shutdown. 10 CFR 54.4(a)(3)

UFSAR References

I.A.4.0
IV.B.7.0
V.B.2.0
VIII.A.1.2

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001
SLR-NMP1-C18005C-002
SLR-NMP1-C18006C-001
SLR-NMP1-C18006C-003
SLR-NMP1-C18007C-001
SLR-NMP1-C18008C
SLR-NMP1-C18009C-001
SLR-NMP1-C18012C-002
SLR-NMP1-C18014C-001
SLR-NMP1-C18015C
SLR-NMP1-C18016C-001
SLR-NMP1-C18017C-001
SLR-NMP1-C18017C-002
SLR-NMP1-C18020C
SLR-NMP1-C18041C-001
SLR-NMP1-C18041C-002
SLR-NMP1-C18041C-004

**Table 2.3.1-3 Reactor Pressure Vessel
Components Subject to Aging Management Review**

Component Type	Intended Function
(N1 Recirculation Outlet) Reactor Vessel Nozzle	Pressure Boundary
(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary
(N11 Low Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary
(N12 Core Differential Press.) Reactor Vessel Nozzle	Pressure Boundary
(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzles	Pressure Boundary
(N18 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary
(N2 Recirculation Inlet) Reactor Vessel Nozzle	Pressure Boundary
(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary
(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N4 Feedwater) Reactor Vessel Nozzle	Pressure Boundary
(N4 Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N4 Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle	Pressure Boundary
(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N6 Core Spray) Reactor Vessel Nozzle	Pressure Boundary
(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N6 Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N7 Top Head Nozzles) Reactor Vessel Nozzle	Pressure Boundary

Component Type	Intended Function
(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N8 Vent) Reactor Vessel Nozzle	Pressure Boundary
(N9 CRDRL) Reactor Vessel Nozzle	Pressure Boundary
(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N9 CRDRL) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
Bolting (Class 1)	Mechanical Closure
Reactor Vessel (Bottom Head, Shells, Top Head, Upper Flange, and Welds)	Pressure Boundary
Reactor Vessel Closure Flange Assembly Components	Mechanical Closure
Reactor Vessel External Surfaces and External Attachments	Structural Support
Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary
	Structural Support to maintain core configuration and flow distribution
Reactor Vessel: shell and associated welds in the beltline region of the vessel	Pressure Boundary

The aging management review results for these components are provided in:

Table 3.1.2-3 Reactor Pressure Vessel
Summary of Aging Management Evaluation

2.3.1.4 **Reactor Pressure Vessel Instrumentation System**

Description

The Reactor Pressure Vessel Instrumentation System is a safety-related instrumentation system that provides a means of monitoring and transmitting information concerning key reactor vessel operating parameters during planned and unplanned operations. The Reactor Pressure Vessel Instrumentation System consists of piping, valves, and instrumentation on the outboard side of the Reactor Coolant Pressure Boundary (RCPB) excess flow check valves.

The Reactor Pressure Vessel Instrumentation System consists of the Reactor instrumentation (pressure, level, controls) plant system and specific CRD instruments monitoring reactor pressure. In addition, the Reactor Pressure Vessel Instrumentation System includes the reactor pressure vessel flange leak detection lines.

Instrumentation, along with associated sensing lines and instrument valves, is installed to monitor reactor parameters such as level, pressure, and temperature and provide indication to the control room, remote shutdown panels, and remote instrument rooms. In addition, the Reactor Pressure Vessel Instrumentation System provides control signals to various systems which in turn initiate the appropriate actions required if the monitored parameter exceeds its desired setpoint.

Intended Functions

1. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Reactor Pressure Vessel Instrumentation System provides input to the reactor protection and engineered safety systems. 10 CFR 54.4(a)(1)
2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Pressure Vessel Instrumentation System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor building. 10 CFR 54.4(a)(2)
3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection. The Reactor Pressure Vessel Instrumentation System provides reactor pressure vessel level and pressure indications for monitoring during safe shutdown activities. 10 CFR 54.4(a)(3)
4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Reactor Pressure Vessel Instrumentation System includes environmentally qualified components. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Reactor Pressure Vessel Instrumentation System monitors steam dome pressure and water level provide input to the Alternate Rod Insertion and ATWS-Recirculation Pump Trip systems.

10 CFR 54.4(a)(3)

6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Reactor Pressure Vessel Instrumentation System supports operations in maintaining reactor coolant inventory and decay heat removal.
10 CFR 54.4(a)(3)

UFSAR References

VI.D.1.0

VIII.C.2.1

License Renewal Boundary Drawings

SLR-NMP1-C18015C

SLR-NMP1-C18016C-001

SLR-NMP1-C18016C-003

SLR-NMP1-C18017C-001

**Table 2.3.1-4 Reactor Pressure Vessel Instrumentation System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping, piping components	Pressure Boundary
Reactor Vessel Flange Leak Detection Line	Leakage Boundary (Spatial)
Valve Body	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.1.2-4 Reactor Pressure Vessel Instrumentation System
Summary of Aging Management Evaluation**

2.3.1.5 **Reactor Pressure Vessel Internals**

Description

The Reactor Pressure Vessel Internals (RPVI) provide support for the core and other internal components; maintain fuel configuration (coolable geometry) during normal operation, plant shutdown, and accident conditions; and provide reactor coolant flow distribution through the core.

The RPVI consist of the components internal to the Reactor Pressure Vessel (RPV). The main components are the fuel bundles, control rod blades, incore instrumentation, core shroud, core shroud repair assemblies, core support, lower plenum flow baffle, top guide, control rod guide tubes and housings, feedwater sparger, core spray annulus piping and spargers, liquid poison sparger, steam separator assembly, and steam dryer assembly. The shroud support essentially sustains all of the vertical weight of the core structure (with the exception of the fuel assemblies) and the steam separator assembly. Each guide tube, with its fuel support casting, bears the weight of four fuel assemblies and rests on a control rod drive housing welded to the stub tube mounted on the vessel bottom head.

Intended Functions

1. Maintain reactor core assembly geometry. The nuclear safety function of the reactor core and internals is to maintain reactor core assembly geometry for any event to ensure core cooling, core reactivity control, and the integrity of the fuel cladding as a radioactive material barrier. 10 CFR 54.4(a)(1)
2. Introduce negative reactivity to achieve or maintain subcritical reactor condition. The nuclear safety function of the reactivity control systems is to achieve and maintain the reactor core subcritical (e.g., control rods, control rod drives). Reactor shutdown by the reactivity control system is sufficiently rapid to prevent violation of fuel damage limits for all operating transients. 10 CFR 54.4(a)(1)
3. Introduce emergency negative reactivity to make the reactor subcritical. The nuclear safety function of the reactivity control systems is to introduce emergency negative reactivity (e.g., liquid poison system, control rod drive scram components) or limit the introduction of positive reactivity. 10 CFR 54.4(a)(1)
4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The intermediate range monitors (IRM) and average power range monitors (APRM) monitor neutron flux and provide logic signals to the reactor protection system (RPS) to initiate a scram to prevent fuel damage resulting from bulk power increases. For a scram to occur, a scram trip signal must be received by both RPS logic channels. Four APRM channels are provided for each RPS logic channel. 10 CFR 54.4(a)(1)
5. Provide emergency core cooling where the equipment provides coolant directly to the core. The design of internal components of the reactor vessel (in conjunction with the reactor vessel) allows adequate core cooling to be maintained during both normal operation and accident conditions without failure. 10 CFR 54.4(a)(1)

6. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The nonsafety-related steam dryer could interact with safety-related components. 10 CFR 54.4(a)(2)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10CFR50.62). The reactor vessel internals include the liquid poison ring sparger for the injection of liquid neutron absorber (sodium pentaborate). The sparger is mounted on the inside shroud surface below the core. The liquid neutron absorber is discharged into the cooling water which then rises upward through the reactor fuel. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The reactor vessel internals include control rod drive (CRD) assemblies and control rod blades which are required for safe shutdown of the reactor. 10 CFR 54.4(a)(3)
9. Relied upon 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). The Reactor Vessel Internals system includes CRD assemblies and control rod blades that are required to achieve and maintain safe shutdown of the reactor. Additionally, the Reactor Vessel Internals system maintains a reactor core coolable geometry. 10 CFR 54.4(a)(3)

UFSAR References

IV.A.2.0
IV.B.1.0
IV.B.3.1.2.3
IV.B.5.0
IV.B.6.0
IV.B.6.2.2
IV.B.7.0
IV.B.7.1
IV.B.7.1.7
IV.B.7.1.8
V.C.2.0
VIII.A.2.1

License Renewal Boundary Drawings

SLR-NMP1-C18007C-001
SLR-NMP1-C18015C

**Table 2.3.1-5 Reactor Pressure Vessel Internals
Components Subject to Aging Management Review**

Component Type	Intended Function
Control Rod Drive Guide Tube	Structural Support to maintain core configuration and flow distribution
Control Rod Drive Guide Tube Base	Structural Support to maintain core configuration and flow distribution
Core Plate DP/SLC Line	Direct Flow
Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution
Core Shroud Support Structure (shroud support cylinder, shroud support plate)	Structural Support to maintain core configuration and flow distribution
Core Spray Sparger Nozzle Elbows	Spray
Core Spray: Piping, spargers, and supports	Spray
	Structural Support
Core plate, core plate bolts, core plate wedges, core plate incore guide tube plugs	Structural Support to maintain core configuration and flow distribution
Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Structural Support to maintain core configuration and flow distribution
	Throttle
Instrumentation: Intermediate range monitor (IRM) dry tubes, source range monitor (SRM) dry tubes; incore neutron flux monitor guide tubes	Structural Support to maintain core configuration and flow distribution
Steam Dryers and Bolted/Welded Clamp Repairs	Structural Support
Top Guide	Structural Support to maintain core configuration and flow distribution

The aging management review results for these components are provided in:

**Table 3.1.2-5 Reactor Pressure Vessel Internals
Summary of Aging Management Evaluation**

2.3.1.6 **Reactor Recirculation System**

Description

The Reactor Recirculation (RR) System consists of the non ASME Class 1 components associated with the recirculation loops, recirculation pumps, and system instrumentation. The recirculation loops including the recirculation pumps, in-line valves, and instrumentation are ASME Class 1 components and as such are addressed as a part of the Reactor Coolant Pressure Boundary System (RCPB). The components in scope of the RR System are limited to instrumentation connected to the recirculation loop via instrumentation piping and the associated valves. Heat exchangers are included in the scope of RR System for the recirculation pump motor, recirculation pump seal cooler, and the motor-generator set. The RR System consists of the following plant system:

- Reactor Recirculation

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The Reactor Recirculation System heat exchangers maintain pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for reactor trip or engineered safety features actuations. The Reactor Recirculation System includes instrumentation that provides input signals to the Reactor Protection System. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Recirculation System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor building. 10 CFR 54.4(a)(2)
4. Relied upon in safety analysis or plant evaluation to perform a function that demonstrates compliance with the commission's regulation for Fire Protection (10 CFR 50.48). The Reactor Recirculation System provides two separate trains, one for each method; preferred and secondary, for process monitoring of reactor pressure vessel temperature indication. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). Reactor Recirculation System components receive the recirculation pump trip signal from the Reactor Protection System and maintains reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
6. Relied upon in safety analysis or plant evaluation to perform a function that demonstrates compliance with the commission's regulation for Station Blackout (10 CFR 50.63). The Reactor Recirculation System provides individual loop and total core flow indication and provides the flow input to the average power range monitor for power to flow protective functions. A transmitter connected across each recirculation pump provides differential pressure indication in the control room.

10 CFR 54.4(a)(3)

UFSAR References

V.B.3.0

VIII.A.2

License Renewal Boundary Drawings

SLR-NMP1-C18006C-003

SLR-NMP1-C18020C

SLR-NMP1-C18022C-002

SLR-NMP1-C18022C-003

**Table 2.3.1-6 Reactor Recirculation System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (R.R.P.M.G Set) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (R.R.P.M.G Set) Tube Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Recirculation Pump Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Recirculation Pump Cooler) Tubes	Pressure Boundary
Heat Exchanger – (Recirculation Pump Motor) Tubes	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.1.2-6 Reactor Recirculation System
Summary of Aging Management Evaluation**

2.3.2 ENGINEERED SAFETY FEATURES

The following systems are addressed in this section:

- Containment Spray System (2.3.2.1)
- Core Spray System (2.3.2.2)
- Emergency Cooling System (2.3.2.3)

2.3.2.1 **Containment Spray System**

Description

The Containment Spray (CTSP) System is a standby system designed to prevent overheating and overpressurization of the containment, reduce drywell airborne fission product concentrations, and control the pressure suppression chamber water temperature following a design basis loss of coolant accident (LOCA). The CTSP System consists of the following plant systems:

- Containment spray, outside drywell
- Containment spray, primary and secondary inside drywell
- Containment spray cooling raw water
- Containment spray cooling raw water intertie

The CTSP System is designed with two redundant loops. The primary loop provides water to the primary or inner drywell sparger and to the torus sparger. The secondary loop provides water to the secondary or outer drywell sparger and to the torus sparger. The torus sparger is common to both loops. Each of the two loops are cross-connected through the test return lines such that each of the loops can provide flow to both the primary and secondary spargers. Each loop includes two redundant trains and consists of two suction headers, two containment spray pumps, two suppression chamber suction strainers, two heat exchangers and the associated containment spray raw water pumps, a common test return line, and associated piping and control valves.

In the event suppression chamber water level falls below the containment spray pump suction level, the raw water pumps can be aligned to supply the containment spray spargers to provide an alternate source of containment cooling. Additionally, the system includes an intertie with the core spray system so that the raw water pumps can be aligned to supply an alternate source of water for the core spray system in the event suppression chamber water level falls below the core spray pump suction level.

Containment spray pump operation is automatically initiated by two reactor protection system signals: high drywell pressure and low-low reactor water level. Automatic initiation of the containment spray pumps occurs following the core spray pumps and core spray topping pumps initiation. Upon containment spray pump initiation, self-actuating check valves open to allow containment spray water to flow through the system. The raw water pumps must be manually initiated following automatic initiation of the containment spray pumps.

Intended Functions

1. Provide emergency heat removal from primary containment and provide containment pressure control. The Containment Spray System removes heat, reduces pressure, and restores the pressure suppression system temperature following a LOCA. The Containment Spray System also ensures the torus water temperature does not exceed that required to satisfy containment spray and core spray pump net positive suction head (NPSH) requirements. 10 CFR 54.4(a)(1)
2. Provide emergency removal of radioactive material from the primary containment atmosphere. The Containment Spray System removes airborne fission products

from the drywell atmosphere following a LOCA to limit fission product releases from containment leakage paths. 10 CFR 54.4(a)(1)

3. Provide primary containment boundary. The Containment Spray System includes primary containment isolation valves. Several valves are provided with a water seal to provide a leak-tight barrier against the uncontrolled release of radioactivity to the environment. 10 CFR 54.4(a)(1)
4. Provide emergency core cooling where the equipment provides coolant directly to the core. The Containment Spray System raw water pumps can be aligned to supply an alternate source of water for the core spray system in the event suppression chamber water level falls below the core spray pump suction level. 10 CFR 54.4(a)(1)
5. Resist nonsafety-related structures, systems, and components (SSCs) failure that could prevent satisfactory accomplishment of a safety-related function. The Containment Spray System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs in the reactor building and screen and pump house. 10 CFR 54.4(a)(2)
6. Relied upon 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). The Containment Spray System has safe shutdown functions to provide a secondary method for decay heat removal and process monitoring of containment spray pressure and temperature indications. The system also includes a non-power operations function to provide reactor vessel inventory control via the core spray system. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Containment Spray System includes environmentally qualified components. 10 CFR 54.4(a)(3)
8. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Containment Spray System includes primary containment isolation valves that are credited for Station Blackout. 10 CFR 54.4(a)(3)

UFSAR References

VII.B

License Renewal Boundary Drawings

SLR-NMP1-C18006C-002
SLR-NMP1-C18006C-003
SLR-NMP1-C18012C-001
SLR-NMP1-C18012C-002
SLR-NMP1-C18022C-001
SLR-NMP1-C18027C-002
SLR-NMP1-C18045C-007

**Table 2.3.2-1 Containment Spray System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Shell Side Components	Pressure Boundary
Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Sheet	Pressure Boundary
Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Side Components	Pressure Boundary
Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Containment Spray Raw Water Pump Motor Cooler) Tubes	Heat Transfer
	Pressure Boundary
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Containment Spray Pumps)	Pressure Boundary
Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary
Spray Nozzles	Spray
Strainer (Element)	Filter
Tanks (Containment Spray Pump Suction Tank)	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.2.2-1 Containment Spray System
Summary of Aging Management Evaluation**

2.3.2.2 Core Spray System

Description

The Core Spray (CS) System is one of the standby emergency core cooling systems (ECCS). The system is designed to mitigate the range of loss of coolant accidents (LOCAs) from the smallest (in conjunction with the automatic depressurization system) up to the largest line break. The CS System consists of the following plant systems:

- Reactor core spray, external isolation valves to high point vent isolation valves
- Reactor core spray, vent and drain
- Reactor core spray
- Reactor core spray, after topping pump

The CS System consists of two separate and independent loops to prevent overheating of the fuel following a LOCA. Each loop has redundant active components within itself. The system automatically starts on reactor vessel low-low water level or high drywell pressure signals from the reactor protection system (RPS). Water is pumped from the suppression pool through suction strainers to a separate ring header located inside the reactor vessel directly above the core. The header sprays water directly onto the fuel bundles in a preestablished pattern.

The CS System is a source of pressurized water to maintain Shutdown Cooling (SDC) System water seals. The water seals are applied to the space between the inboard and outboard shutdown cooling isolation valves and provide a water seal for the containment isolation valves when containment isolation is required (reactor vessel low-low water level or high drywell pressure). Since the seal water can be provided from either CS System loop, the water seal is maintained regardless of which loop is in operation.

The Class 1 portion of the CS System includes containment isolation valves and piping. These SSCs are included in the Reactor Coolant Pressure Boundary System. The Core Spray ring headers are included in the Reactor Vessel Internals System.

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the core. The Core Spray System automatically sprays water into the reactor vessel onto the top of the fuel assemblies to cool the core in the event of a LOCA.
10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Core Spray System includes piping and valves that are part of the primary containment boundary. The Core Spray System supplies water to the Shutdown Cooling System to support containment isolation by providing a water seal to the shutdown cooling containment penetrations.
10 CFR 54.4(a)(1)
3. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Core Spray System includes instrumentation that provides signals for interlocks, automatic controls, and to initiate credited manual actions.
10 CFR 54.4(a)(1)

4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Core Spray System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
5. Relied upon 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). The Core Spray System provides inventory control during Fire Safe Shutdown. 10 CFR 54.4(a)(3)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Core Spray System includes environmentally qualified components. 10 CFR 54.4(a)(3)
7. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Core Spray System includes primary containment isolation valves that are credited for Station Blackout. 10 CFR 54.4(a)(3)

UFSAR References

VII.A

License Renewal Boundary Drawings

SLR-NMP1-C18006C-001
 SLR-NMP1-C18006C-002
 SLR-NMP1-C18007C-001
 SLR-NMP1-C18007C-002
 SLR-NMP1-C18012C-001

**Table 2.3.2-2 Core Spray System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Core Spray Pump Motor Coolers) Tube Side Components	Pressure Boundary
Heat Exchanger – (Core Spray Pump Motor Coolers) Tubes	Heat Transfer
	Pressure Boundary
Piping elements	Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)
Pump Casing (Core Spray Pumps)	Pressure Boundary
Pump Casing (Core Spray Topping Pumps)	Pressure Boundary
Strainer (Element)	Filter
Tanks (Core Spray Pump Stuffing Box Lube Tank)	Structural Integrity (Attached)
Tanks (Core Spray Pump Suction Tanks)	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)

The aging management review results for these components are provided in:

**Table 3.2.2-2 Core Spray System
Summary of Aging Management Evaluation**

2.3.2.3 Emergency Cooling System

Description

The Emergency Cooling (EC) System is a standby system that provides for decay heat removal from the reactor fuel in the event that reactor feedwater capability is lost and the main condenser is not available. The EC System consists of the following plant systems:

- Emergency condenser vent to main steam line and bypass to torus
- Emergency condenser vent to torus (from bypass valve to emergency condenser vent to torus blocking valve to torus)
- Emergency condenser vent to torus
- Emergency condenser, steam supply and condensate return
- Emergency condenser makeup and makeup tank overflow
- Emergency condenser shell vent, drain and overflow

The EC System is connected to the reactor and operates by natural circulation. This system serves as an alternate heat sink when the reactor is isolated from the condenser (the normal heat sink). Automatic operation of the system is initiated by sustained high reactor pressure or sustained low-low reactor water level. The system can also be initiated manually.

Each of the two independent emergency cooling loops include two condensers, consisting of a tube bundle in a tank located above the reactor vessel. Each loop contains an elevated makeup water tank with gravity feed to the condensers. Both makeup tanks in the system are cross-tied via a common line, which allows the system to operate using only one loop while utilizing both tanks. The normal makeup water source to the makeup tanks is the condensate storage tanks via the condensate transfer system. The fire water system provides a long-term source of water to the makeup tanks to support the emergency cooling system's function to achieve and maintain hot shutdown after a fire.

The Class 1 portion of the EC System includes containment isolation valves and piping. These SSCs are included in the Reactor Coolant Pressure Boundary System.

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the core. The Emergency Cooling System provides for the removal of decay heat after reactor scram, when the main condenser is not available as a heat sink, or in the event that reactor feedwater capability is lost. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Emergency Cooling System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Emergency Cooling System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs in the reactor and turbine buildings. 10 CFR 54.4(a)(2)

4. Relied upon 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). The Emergency Cooling System provides decay heat removal during Fire Safe Shutdown. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Emergency Cooling System includes environmentally qualified components. 10 CFR 54.4(a)(3)
6. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Emergency Cooling System provides decay heat removal during Station Blackout coping and recovery. 10 CFR 54.4(a)(3)

UFSAR References

V.E

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001
 SLR-NMP1-C18003C-001
 SLR-NMP1-C18006C-001
 SLR-NMP1-C18006C-002
 SLR-NMP1-C18009C-001
 SLR-NMP1-C18017C-001
 SLR-NMP1-C18017C-002
 SLR-NMP1-C18045C-007
 SLR-NMP1-C18048C

**Table 2.3.2-3 Emergency Cooling System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Expansion Joints	Pressure Boundary
Heat Exchanger – (Emergency Condensers) Shell Side Components	Pressure Boundary
Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary
Heat Exchanger – (Emergency Condensers) Tube Side Components	Pressure Boundary
Heat Exchanger – (Emergency Condensers) Tubes	Heat Transfer
	Pressure Boundary
Piping elements	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Tanks (Emergency Condenser Make Up Water Tanks)	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.2.2-3 Emergency Cooling System
Summary of Aging Management Evaluation**

2.3.3 AUXILIARY SYSTEMS

The following systems are addressed in this section:

- Circulating Water System (2.3.3.1)
- City Water System (2.3.3.2)
- Compressed Air Systems (2.3.3.3)
- Containment Systems (2.3.3.4)
- Control Room HVAC System (2.3.3.5)
- Cranes, Hoists, and Refueling Equipment System (2.3.3.6)
- Electric Steam Boiler System (2.3.3.7)
- Emergency Diesel Generator System (2.3.3.8)
- Fire Detection and Protection System (2.3.3.9)
- Liquid Poison System (2.3.3.10)
- Makeup Demineralizer System (2.3.3.11)
- Radioactive Waste System (2.3.3.12)
- Reactor Building Closed Loop Cooling System (2.3.3.13)
- Reactor Building HVAC System (2.3.3.14)
- Reactor Water Cleanup (2.3.3.15)
- Sampling System (2.3.3.16)
- Service Water System (2.3.3.17)
- Shutdown Cooling System (2.3.3.18)
- Spent Fuel Pool Cooling and Storage System (2.3.3.19)
- Turbine Building Closed Loop Cooling System (2.3.3.20)
- Turbine Building HVAC System (2.3.3.21)

2.3.3.1 Circulating Water System

Description

The purpose of the Circulating Water (CWS) System is to provide cooling water to the main condenser to condense the exhaust steam from the main turbine. The CWS System consists of the following plant systems:

- Screen wash
- Main condenser circulating water
- Hydraulic fluid to the tempering gate actuator
- Circulating and service water chemical addition system
- Main condenser circulating water box vents

The CWS System consists of two circulating water pumps located in the screenhouse which deliver lake water to the condenser water box. Each pump discharges into a separate line to one side of the condenser divided water box. The CWS System includes traveling screens which are located downstream of the trash racks in the intake tunnel. The traveling screens provide removal of small debris. The traveling screens are required for removal of debris in support of fire pump operation pursuant to NFPA requirements. Two screen wash pumps provide water from the Service Water System to clean debris from the travelling screens.

With the exception of the traveling screens, the intended function of the CWS System for license renewal is to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid-filled portions of the system located within the screen and pump house.

Trash racks and gates located in the screen and pumphouse are evaluated with the Screen and Pump House Building. Except for the tempering gate hydraulic lifting device, the cranes, trolleys, and hoists in the screen and pump house are evaluated with the Cranes, Hoist, and Refueling Equipment System.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Circulating Water System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interaction that could cause failure of safety-related SSCs located in the screen and pump house. 10 CFR 54.4 (a)(2)
2. Relied upon 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). The traveling screens are required for removal of debris in support of fire pump operation pursuant to NFPA requirements. 10 CFR 54.4 (a)(3)

UFSAR References

XI.B.4.0
XII.2.2.1.1
XII.2.2.2

License Renewal Boundary Drawings

SLR-NMP1-B26941C
SLR-NMP1-B35715C
SLR-NMP1-C18010C-001
SLR-NMP1-C18010C-005
SLR-NMP1-C18022C-001
SLR-NMP1-C18022C-005
SLR-NMP1-C18029C-001

**Table 2.3.3-1 Circulating Water System
Components Subject to Aging Management Review**

Component Type	Intended Function
Accumulator (Chemical Addition Pulsation Damper)	Leakage Boundary (Spatial)
Bolting (Closure)	Mechanical Closure
Bolting (Traveling Screens)	Structural Support
Expansion Joints	Leakage Boundary (Spatial)
Flexible Connection	Leakage Boundary (Spatial)
Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Tube Side Components	Leakage Boundary (Spatial)
Hoses	Leakage Boundary (Spatial)
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump Casing (Circulating Water Pump)	Leakage Boundary (Spatial)
Pump Casing (Condenser Waterbox Priming Pump)	Leakage Boundary (Spatial)
Pump Casing (Deposit Penetrant Pump)	Leakage Boundary (Spatial)
Pump Casing (Dispersant Pump)	Leakage Boundary (Spatial)
Pump Casing (Hydraulic Pump)	Leakage Boundary (Spatial)
Pump Casing (Screen Wash Pump)	Leakage Boundary (Spatial)
Pump Casing (Sodium Bisulfite Pump)	Leakage Boundary (Spatial)
Pump Casing (Sodium Bromide Pump)	Leakage Boundary (Spatial)
Pump Casing (Sodium Hypochlorite Pump)	Leakage Boundary (Spatial)
Tanks (100 Gallon Reservoir)	Leakage Boundary (Spatial)
Tanks (Condenser Waterbox Priming Sump Volume Chamber)	Leakage Boundary (Spatial)
Tanks (Deposit Penetrant Tank)	Leakage Boundary (Spatial)
Tanks (Moisture Separator)	Leakage Boundary (Spatial)
Tanks (Sodium Bromide Tank)	Leakage Boundary (Spatial)
Traveling Water Screens (Revolving Screen)	Filter
Valve Body	Leakage Boundary (Spatial)

The aging management review results for these components are provided in:

**Table 3.3.2-1 Circulating Water System
Summary of Aging Management Evaluation**

2.3.3.2 City Water System

Description

The City Water (CTW) System consists of the following plant systems:

- City Water (Cold)
- City Water (Hot)
- City Water, Potable Service (Underground)
- City Water, Potable Service (Above Ground)

The intended function of the CTW System for license renewal is to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid-filled portions of the system located within the turbine building and screenhouse. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system. This system is not required to operate to support other license renewal intended functions and is in scope only for potential spatial interaction.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The City Water System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the turbine building and screenhouse. 10 CFR 54.4(a)(2).

UFSAR References

X.G

License Renewal Boundary Drawings

SLR-NMP1-C18034C-003
SLR-NMP1-C18036C
SLR-NMP1-B18042C-001
SLR-NMP1-B18042C-002

**Table 2.3.3-2 City Water System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump Casing (Heating System Recirculation Pump)	Leakage Boundary (Spatial)
Pump Casing (Hot Water Recirculating Pumps)	Leakage Boundary (Spatial)
Tanks (City Water Hot Water Heaters)	Leakage Boundary (Spatial)
Tanks (City Water Storage Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)

The aging management review results for these components are provided in:

**Table 3.3.2-2 City Water System
Summary of Aging Management Evaluation**

2.3.3.3 **Compressed Air Systems**

Description

The Compressed Air Systems are normally operating systems that are in scope for license renewal. The Compressed Air Systems (CA) consists of the following plant systems:

- Instrument air
- House service air
- Breathing air

Instrument Air

The instrument air system is comprised of a safety-related portion and a nonsafety-related portion. Both portions supply filtered, compressed, cooled, and dried air to air operated instruments throughout the plant and to the containment spray system test receiver. The purpose is to provide a control and/or motive force to equipment, for example to open or close a valve as well as testing of the containment spray system. In addition, the system supplies process air to various radwaste systems. The Instrument Air System may also be used as a backup source of air for the breathing air system via a manual crosstie.

The system consists of three two-stage air compressors, three receivers, three dryers, and four outlet filters. Accompanying each compressor is an inlet filter, intercooler, and aftercooler (including its associated moisture separator). Two of the compressors are safety-related and backup the nonsafety-related compressor which normally operates to supply total system demand. The safety-related compressors draw their air through inlets located on the turbine building roof. The nonsafety-related compressor draws outside air through an intake located on the roof of the off-gas building and through a filter.

Service Air

The service air system is a nonsafety-related system which supplies filtered, compressed, and cooled service air to stations throughout the plant to which air operated tools can be attached. The purpose is to allow easy access to an air supply for maintenance work to be performed throughout the plant. In addition, the service air system provides process and supervisory air to nonsafety-related systems (i.e., radwaste and fire protection). The service air system also provides a backup source of air to the instrument air system through an automatic crosstie.

The system consists of one two-stage air compressor, an intercooler and aftercooler (including its associated moisture separator), one filter and a receiver. The compressor draws outside air through an intake located on the roof of the turbine building and through a filter.

Breathing Air

The breathing air system is a nonsafety-related system which supplies filtered, compressed, and cooled breathing air to stations throughout the plant to which personal

respiratory protection equipment can be attached. The purpose is to prevent personnel from inhaling airborne particulate contaminants when entering airborne radioactivity areas. Airline respirators connected to the breathing air system are not used in atmospheres that are Immediately Dangerous to Life or Health (IDLH).

The system consists of one single-stage air compressor, an aftercooler (including its associated moisture separator), three filters, and a receiver. The compressor draws outside air through an intake located on the roof of the turbine building and through a filter.

The diesel starting air system is included in the Emergency Diesel Generator System.

Intended Functions

1. Provide primary containment boundary. The Compressed Air Systems contain primary containment isolation valves and lines that penetrate containment. 10 CFR 54.4 (a)(1)
2. Provide secondary containment boundary. The Compressed Air Systems contain secondary containment isolation valves and piping that penetrate secondary containment with lines that run from the turbine building into the reactor building. 10 CFR 54.4 (a)(1)
3. Provide motive power to safety-related components. The Compressed Air Systems provide an adequate supply of clean dry air to safety-related components for control, motive force or other purposes as required by the serviced safety-related components. 10 CFR 54.4 (a)(1)
4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Compressed Air Systems include nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. The Compressed Air System also includes nonsafety-related components that maintain mechanical and structural integrity to provide structural support to attached safety-related piping. 10 CFR 54.4(a)(2)
5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Includes nonsafety-related SSCs that are functionally relied upon to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or (b) directly mitigate the consequences of a design basis event (DBE). The Compressed Air Systems provide air to CRD and FW/HPCI System components that perform an (a)(2) functional intended function that provide water to the reactor during small-break loss of coolant accident events. In addition, there are portions of the Compressed Air System that are nonsafety-related that preserve the pressure boundary of safety-related portions of the system. 10 CFR 54.4(a)(2)
6. Relied upon 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). The Compressed Air Systems supply air to the safety/relief valves and automatic depressurization system which are required to remain functional to

ensure safe shutdown capability. 10 CFR 54.4(a)(3)

7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Compressed Air System includes environmentally qualified components. 10 CFR 54.4(a)(3)

UFSAR References

X.I.1.0

X.I.3.0

License Renewal Boundary Drawings

SLR-NMP1-A22108C-004
SLR-NMP1-A22108C-005
SLR-NMP1-A22108C-006
SLR-NMP1-A22108C-007
SLR-NMP1-A22108C-009
SLR-NMP1-A22108C-010
SLR-NMP1-A22108C-013
SLR-NMP1-A22108C-014
SLR-NMP1-A22108C-018
SLR-NMP1-A22108C-019
SLR-NMP1-A22108C-020
SLR-NMP1-A22108C-023
SLR-NMP1-A22108C-024
SLR-NMP1-A22108C-027
SLR-NMP1-A22108C-028
SLR-NMP1-A22108C-029
SLR-NMP1-A22108C-031
SLR-NMP1-A22108C-032
SLR-NMP1-A22108C-033
SLR-NMP1-A22108C-034
SLR-NMP1-A22108C-042
SLR-NMP1-A22108C-047
SLR-NMP1-A22108C-053
SLR-NMP1-A22108C-13A
SLR-NMP1-A22110C-001
SLR-NMP1-A22110C-002
SLR-NMP1-A22110C-006
SLR-NMP1-A22110C-007
SLR-NMP1-A22110C-008
SLR-NMP1-A22110C-009
SLR-NMP1-A22110C-010
SLR-NMP1-A22110C-011
SLR-NMP1-A22110C-012
SLR-NMP1-A22110C-014
SLR-NMP1-A22110C-015
SLR-NMP1-A22110C-016
SLR-NMP1-A22110C-017

SLR-NMP1-A22110C-018
SLR-NMP1-A22110C-019
SLR-NMP1-A22110C-020
SLR-NMP1-A22110C-021
SLR-NMP1-A22110C-022
SLR-NMP1-A22110C-023
SLR-NMP1-A22110C-024
SLR-NMP1-A22110C-025
SLR-NMP1-A22110C-026
SLR-NMP1-A22110C-027
SLR-NMP1-A22110C-028
SLR-NMP1-A22110C-029
SLR-NMP1-A22110C-030
SLR-NMP1-A22110C-033
SLR-NMP1-A22110C-034
SLR-NMP1-A22110C-035
SLR-NMP1-A22110C-036
SLR-NMP1-A22110C-037
SLR-NMP1-A22110C-038
SLR-NMP1-A22110C-039
SLR-NMP1-A22110C-040
SLR-NMP1-A22110C-041
SLR-NMP1-A22110C-042
SLR-NMP1-A22110C-043
SLR-NMP1-A22110C-044
SLR-NMP1-A22110C-045
SLR-NMP1-A22110C-046
SLR-NMP1-A22110C-047
SLR-NMP1-A22110C-048
SLR-NMP1-A22110C-049
SLR-NMP1-A22112C-001
SLR-NMP1-A22112C-003
SLR-NMP1-A22112C-004
SLR-NMP1-A22112C-005
SLR-NMP1-A22112C-006
SLR-NMP1-A22112C-007
SLR-NMP1-A22112C-008
SLR-NMP1-A22112C-009
SLR-NMP1-A22112C-010
SLR-NMP1-A22116C-020
SLR-NMP1-B22109C-001
SLR-NMP1-B22109C-003
SLR-NMP1-B22109C-004
SLR-NMP1-B22109C-005
SLR-NMP1-B22109C-006
SLR-NMP1-B22109C-007
SLR-NMP1-B22109C-009
SLR-NMP1-B22109C-010
SLR-NMP1-B22109C-012
SLR-NMP1-B22109C-10A

SLR-NMP1-B22111C-001
SLR-NMP1-B22111C-002
SLR-NMP1-B22111C-003
SLR-NMP1-B22111C-004
SLR-NMP1-B22111C-005
SLR-NMP1-B22111C-006
SLR-NMP1-B22111C-007
SLR-NMP1-B22111C-009
SLR-NMP1-B22113C-001
SLR-NMP1-B22113C-002
SLR-NMP1-B22117C-001
SLR-NMP1-B26787C
SLR-NMP1-C18003C-002
SLR-NMP1-C18005C-003
SLR-NMP1-C18006C-003
SLR-NMP1-C18011C-001
SLR-NMP1-C18011C-002
SLR-NMP1-C18011C-003
SLR-NMP1-C18011C-004
SLR-NMP1-C18011C-005
SLR-NMP1-C18011C-006
SLR-NMP1-C18012C-002
SLR-NMP1-C18016C-001
SLR-NMP1-C18016C-002
SLR-NMP1-C18019C
SLR-NMP1-C18022C-003
SLR-NMP1-C18034C-002
SLR-NMP1-C18242C
SLR-NMP1-C18668C-002
SLR-NMP1-C22118C-004
SLR-NMP1-C22131C-001
SLR-NMP1-C26696C
SLR-NMP1-C26712C-001

**Table 2.3.3-3 Compressed Air Systems
Components Subject to Aging Management Review**

Component Type	Intended Function
Accumulator (Scram Air Volume)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (Breathing Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Breathing Air Compressor Aftercooler) Tube Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Breathing Air Compressor Intercooler) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Breathing Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Service Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Service Air Compressor Aftercooler) Tube Side Components	Leakage Boundary (Spatial)

Component Type	Intended Function
Heat Exchanger – (Service Air Compressor Intercooler) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Service Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)
Hoses	Pressure Boundary
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)
Silencer / Muffler	Structural Support
Strainer (Element)	Filter
Tanks (Afterfilters)	Pressure Boundary
Tanks (Breathing Air Aftercooler Moisture Separator)	Structural Integrity (Attached)
Tanks (Breathing Air Receiver)	Structural Integrity (Attached)
Tanks (Containment Spray System Air Test Receiver)	Pressure Boundary
Tanks (Feedwater Flow Control Valve Receiver)	Structural Integrity (Attached)
Tanks (Instrument Air Aftercooler Moisture Separators)	Pressure Boundary
Tanks (Instrument Air Dryer Chambers)	Pressure Boundary
Tanks (Instrument Air Receiver #11)	Pressure Boundary
Tanks (Instrument Air Receiver #12)	Pressure Boundary
Tanks (Reactor Building Door Seal Receiver)	Structural Integrity (Attached)
Tanks (Service Air Aftercooler Moisture Separator)	Pressure Boundary
Tanks (Service Air Receiver)	Structural Integrity (Attached)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)

The aging management review results for these components are provided in:

Table 3.3.2-3 Compressed Air Systems
Summary of Aging Management Evaluation

2.3.3.4 **Containment Systems**

Description

The Containment Systems are designed to control and monitor the primary containment environment. The Containment Systems consist of the following plant systems:

- Drywell and torus vacuum relief
- Torus drains
- Torus dewatering
- Reactor containment cooling, air purge and fill, section inside vessel and outside vessel beyond outside isolation valve
- Drywell vent and purge air and N₂ (drywell to first isolation valve, also instrument on O₂ analyze system, and traversing incore probe (TIP) index purge inside the drywell to the first isolation valve)
- Reactor containment (drywell and torus) inert gas (N₂) supply from N₂ blocking valve to torus and N₂ blocking valve to drywell to junction with reactor containment cooling, air purge and fill system
- Reactor containment N₂ purge and fill, N₂ supply from storage tank to range radiation monitor system equipment
- Hardened containment vent system
- Reactor containment N₂ purge and fill, leak rate monitoring (N₂) inside drywell vessel
- Leak rate monitoring, outside drywell (N₂) to and including automatic isolation valve
- Containment radiation monitoring and containment H₂/O₂ monitoring
- Reactor containment N₂ purge and fill, new equipment in N₂ supply
- Reactor containment (drywell and torus) inert gas N₂ supply from and including N₂ Storage tank up to and including valve N₂ blocking valve to torus and N₂ blocking valve to drywell
- Incore monitoring, transversing incore probe system
- Torus temperature monitoring system

These systems work together to accomplish five functional operations; combustible gas control, primary containment area cooling, primary containment monitoring and torus drains, integrated leak rate monitoring, and hardened containment vent.

Combustible gas control

The containment inerting system and the containment atmospheric dilution system work to maintain a containment atmosphere free from a combustible atmosphere. The containment inerting system maintains an elevated nitrogen concentration and low oxygen concentration such that hydrogen generation immediately following a loss of coolant accident (LOCA) does not create a combustible atmosphere. Long term post-LOCA coping strategies will sample the containment atmosphere as hydrogen and oxygen may continue to be released to the containment atmosphere. The containment atmospheric dilution system will add nitrogen as needed to prevent a combustible atmosphere and potentially vent containment through the reactor building emergency ventilation system to avoid over pressurization. Both systems use much of the same piping and equipment to accomplish their functions. The combustible gas control system is also a source of nitrogen for various plant systems including the neutron monitoring incore probe system.

Primary containment area cooling

The primary containment area cooling system is provided to remove and dissipate the primary containment area heat gain. During normal operation, heat is released to the drywell as heat losses from the reactor, pump motors, hot pipes, and other equipment. Drywell cooling is accomplished by fan type coolers which use the reactor building closed loop cooling system to remove heat. Operation of cooler fans during purge and fill operations of the containment inerting system also provides for maximum mixing in containment.

Primary containment monitoring system and torus drains

The primary containment monitoring system provides information on primary containment environmental conditions. The containment atmospheric monitoring system continuously monitors and provides control room indication of the containment airborne radioactivity level. This provides for detection of leaks of the reactor primary systems.

The drywell monitoring instrumentation provides information on drywell temperature, pressure, humidity, and primary containment water level to ensure that the conditions are maintained in the correct temperature range for equipment protection and that the structural integrity of containment is assured. The radiation level of the drywell is also constantly monitored by the drywell high range radiation monitors and displayed in the control room.

The torus temperature monitoring system provides information on torus temperature. Torus level and torus airspace pressure are also monitored. These parameters are monitored to ensure that the cooling capacity of water maintained in the suppression chamber is available within the Technical Specification limits and to ensure that the containment structural integrity is maintained.

The suppression chamber room level instrument acts to monitor suppression chamber leakage and trips sump pumps if level is high.

The torus drain system is used when the reactor is in cold shutdown or refueling condition and allows the torus to be dewatered to permit maintenance or other activities.

Integrated leak rate monitoring

The integrated leak rate monitoring system is used to support periodic testing for overall leakage from primary containment. This is done to conform with Technical Specification limits and 10 CFR 50 Appendix J and demonstrates the ability of containment to control the spread of radioactivity in the event of an accident.

Hardened containment vent

The hardened containment vent system is designed to be operated during a beyond design basis external event. The primary function of this system is to provide sufficient venting capacity to prevent a long-term overpressure failure of primary containment by keeping the primary containment pressure below the Primary Containment Pressure Limit.

Intended Functions

1. Provide primary containment boundary. The Containment Systems include piping and primary containment isolation valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
2. Provide secondary containment boundary. The Containment Systems hardened vent includes piping and tubing that pass through the secondary containment and function to maintain the secondary containment pressure boundary. 10 CFR 54.4(a)(1)
3. Provide heat removal from safety-related heat exchangers. The Containment Systems drywell air coolers cooling coils maintain pressure boundary of the reactor building closed loop cooling system as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)
4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Containment Systems include drywell pressure elements which are relied on to send signals to transmitters which provide reactor protection system for various protective system functions, including reactor scram, containment isolation, containment spray system initiation, automatic depressurization system initiation, and control room emergency ventilation system initiation. Additionally, the torus temperature monitoring system provides bulk temperature indication which prompts manual initiation of the containment spray system torus cooling mode to ensure that torus water temperature does not exceed that required to satisfy containment spray and core spray pump net positive suction head (NPSH) requirements. 10 CFR 54.4(a)(1)
5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Containment Systems include nonsafety-related components that maintain mechanical and structural integrity to provide structural support to attached safety-related piping. 10 CFR 54.4(a)(2)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Containment Systems include electrical equipment subject to the requirements of 10CFR50.49, the EQ rule. 10 CFR 54.4(a)(3)
7. Relied upon 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). The Containment Systems include instrumentation credited for safe shutdown and non-power operations. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Containment Systems include equipment to cope with a complete loss of offsite and onsite power. The Containment Systems provide coping support through monitoring drywell pressure and temperature. 10 CFR 54.4(a)(3)
9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated

Transients Without Scram (10 CFR 50.62). The Containment Systems include equipment which provides the primary containment ventilation path to the reactor building emergency ventilation for iodine filtration. Additionally, the Containment Systems provide torus temperature monitoring. 10 CFR 54.4(a)(3)

UFSAR References

VI

VII.G

License Renewal Boundary Drawings

SLR-NMP1-C18006C-001
SLR-NMP1-C18006C-002
SLR-NMP1-C18006C-003
SLR-NMP1-C18009C-001
SLR-NMP1-C18012C-002
SLR-NMP1-C18013C
SLR-NMP1-C18014C-001
SLR-NMP1-C18014C-002
SLR-NMP1-C18014C-003
SLR-NMP1-C18014C-005
SLR-NMP1-C18014C-006
SLR-NMP1-C18014C-007
SLR-NMP1-C18022C-002
SLR-NMP1-C26939C
SLR-NMP1-C26949C

**Table 2.3.3-4 Containment Systems
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (Ambient Vaporizer) Fins	Heat Transfer
Heat Exchanger – (Ambient Vaporizer) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Drywell Air Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Drywell Air Cooler) Tubes	Pressure Boundary
Piping, piping components	Pressure Boundary
	Structural Integrity (Attached)
Rupture Disks	Pressure Boundary
Strainer (Element)	Filter
Tanks (Inner N2 Storage Tank)	Pressure Boundary
Tanks (Outer N2 Storage Tank)	Pressure Boundary
Valve Body	Pressure Boundary
	Structural Integrity (Attached)

The aging management review results for these components are provided in:

**Table 3.3.2-4 Containment Systems
Summary of Aging Management Evaluation**

2.3.3.5 **Control Room HVAC System**

Description

The Control Room HVAC (CRV) System is a normally operating system that provides a continuous flow of filtered, heated, or cooled air throughout the control complex while maintaining a positive pressure to prevent infiltration of potentially contaminated air. The CRV System includes the following plant systems:

- Control room ventilation system
- Control room ventilation chilled water system

The plant control room ventilation system consists of both a normal ventilation system and an emergency ventilation system. The normal ventilation system provides outside air and recirculated air for heating and cooling the control complex during normal operation. The emergency ventilation system is a standby system which is automatically initiated on a high radiation signal from the air intake radiation monitors, loss of coolant accident (LOCA), or a main steam line break (MSLB) signal from the reactor protection system (RPS). Upon initiation, the normal ventilation supply isolation dampers will automatically close and the emergency ventilation inlet dampers will automatically open. The emergency ventilation air supply is treated by a high efficiency particulate filter and an activated charcoal filter unit. The treated air is distributed through the normal supply ductwork, mixes with the control room return air and circulated by the normal control room ventilation circulation fan. The emergency ventilation system can also be initiated manually.

Cooling for the control complex is provided by two redundant cooling coils. The cooling coils are supplied with chilled water from the control room ventilation chilled water system which includes two redundant chiller units. Heating for the control complex is provided by thermostatically controlled duct mounted electric heaters.

The CRV System includes an independent manually operated smoke purge system consisting of an exhaust system and air make-up system. The system is designed to provide a once through system to remove smoke and heat from the main control room, the auxiliary control room, and the cable spreading room. Fire dampers associated with the CRV System are evaluated in the Fire Detection and Protection System.

Intended Functions

1. Provide centralized area for control and monitoring of nuclear safety-related equipment. The Control Room HVAC System maintains the control complex atmosphere suitable for occupancy throughout the duration of design basis accidents. 10 CFR 54.4(a)(1)
2. Maintain emergency temperature limits within areas containing safety-related components. The Control Room HVAC System maintains environmental conditions to ensure the operability of safety-related equipment in the control complex. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Control Room HVAC System chilled water system

includes nonsafety-related components (side stream demineralizer) that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the turbine building. 10 CFR 54.4(a)(2)

4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10CFR 50.48). The Control Room HVAC System is credited to reach and maintain safe and stable conditions in event of a fire. The system is also credited for smoke removal in the main control room, auxiliary control room, and cable spreading room. 10 CFR 54.4(a)(3)

UFSAR References

III.B.1.4

III.B.2.2

III.B.2.3

License Renewal Boundary Drawings

SLR-NMP1-C18021C-002

SLR-NMP1-C18022C-002

SLR-NMP1-C18046C-001

SLR-NMP1-C18047C-001

SLR-NMP1-C18047C-002

**Table 2.3.3-5 Control Room HVAC System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Bolting (Ducting Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Ducting and Components: Insulated	Pressure Boundary
Flexible Connection	Pressure Boundary
Heat Exchanger – (Admin Bldg. Supply) Tube Side Components	Pressure Boundary
Heat Exchanger – (Admin Bldg. Supply) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Chiller Condenser) Shell Side Components	Pressure Boundary
Heat Exchanger – (Chiller Condenser) Tube Sheet	Pressure Boundary
Heat Exchanger – (Chiller Condenser) Tube Side Components	Pressure Boundary
Heat Exchanger – (Chiller Condenser) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Chiller Evaporator) Shell Side Components: Insulated	Pressure Boundary
Heat Exchanger – (Chiller Evaporator) Tube Sheet	Pressure Boundary
Heat Exchanger – (Chiller Evaporator) Tube Side Components: Insulated	Pressure Boundary
Heat Exchanger – (Chiller Evaporator) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Cooling Coil #11 & #12) Shell Side Components	Pressure Boundary
Heat Exchanger – (Cooling Coil #11 & #12) Tube Side Components	Pressure Boundary
Heat Exchanger – (Cooling Coil #11 & #12) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Lab Air Supply Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Lab Air Supply Cooler) Tubes	Pressure Boundary
Piping, piping components, Insulated	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Chilled Water Circ Pump): Insulated	Pressure Boundary
Strainer (Element)	Filter

Component Type	Intended Function
Tanks (Chilled Water Expansion Tank)	Pressure Boundary
Tanks (Chilled Water Side Stream Demineralizer)	Leakage Boundary (Spatial)
Valve Body, Insulated	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

Table 3.3.2-5 Control Room HVAC System
Summary of Aging Management Evaluation

2.3.3.6 **Cranes, Hoists, and Refueling Equipment System**

Description

The Cranes, Hoists and Refueling Equipment System is comprised of load handling bridge cranes, jib cranes, lifting devices, monorails, and hoists provided throughout the facility to support operation and maintenance activities. Also included are equipment that handles fuel and other light loads above fuel and other safety-related components. The Cranes, Hoists and Refueling Equipment System is in scope for license renewal. However, portions of the Cranes, Hoists and Refueling Equipment System are not required to perform intended functions and are not in scope.

The Cranes, Hoists, and Refueling Equipment System also consists of the fuel handling system, equipment to support fuel handling operations, and the hoists, cranes, and elevators systems.

The following heavy load handling systems meet the NUREG-0612 requirements for moving heavy loads and are in scope for license renewal or support fuel handling operations:

- Reactor building 125-ton overhead traveling crane with 25-ton auxiliary hoist
- Portable jib crane servicing spent fuel pool and the new fuel vault (six installation locations)
- Turbine building 150-ton overhead traveling crane with 35-ton auxiliary hoist
- Screenhouse 25-ton overhead traveling crane with 5-ton auxiliary hoist
- Screenhouse gate hoists A, B, C, and D
- Refueling platform with a main hoist and two auxiliary hoists
- Fuel prep machine

It is noted that the screenhouse gate hoists have no rails, bridges, or structural members and are considered active assemblies not subject to AMR. The hoists are supported by the screenhouse structure which is addressed in the Screen and Pump House Structure Scoping Report.

Intended Functions

1. Provides structural support or restraint to SSCs in the scope of license renewal. The screenhouse gate hoists (A through D) are used to maintain the intake, outlet and reversing gates in the appropriate positions to assure a flow path from and to the ultimate heat sink. 10 CFR 54.4(a)(1)
2. Provides a safe means for handling safety-related components and loads above or near safety-related components. The Cranes, Hoists, and Refueling Equipment System contains nonsafety-related components within the scope of license renewal that handle equipment above or near safety-related components or spent fuel. 10 CFR 54.4(a)(2)
3. Relied upon 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). The screenhouse gate hoists are used to position screenhouse gates as needed to assure fire protection equipment is provided with a source of

water. 10 CFR 54.4(a)(3)

UFSAR References

X.J.2

III.F.1.2

License Renewal Boundary Drawings

None.

**Table 2.3.3-6 Cranes, Hoists, and Refueling Equipment System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Structural)	Structural Support
Crane/Hoist (Fuel Prep Machine)	Structural Support
Crane/Hoist (Refueling Platform)	Structural Support
Crane/Hoist: rails, bridges, structural members, structural components	Structural Support

The aging management review results for these components are provided in:

**Table 3.3.2-6 Cranes, Hoists, and Refueling Equipment System
Summary of Aging Management Evaluation**

2.3.3.7 **Electric Steam Boiler System**

Description

The Electric Steam Boiler (EB) System consists of the following plant systems:

- Electric steam boilers
- Liquid waste system cleaning (hot mixture of condensate and steam)
- Miscellaneous equipment vents connected to building ventilation duct

The intended function of the EB System for license renewal is to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid and steam filled portions of the system located within the reactor, turbine, and offgas buildings. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system. This system is not required to operate to support other license renewal intended functions and is in scope only for potential spatial interaction.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Electric Steam Boiler System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs.
10 CFR 54.4(a)(2)

UFSAR References

VI.E.2

VII.H

Table XVI-29

Table XVI-30

Table XII-4

License Renewal Boundary Drawings

SLR-NMP1-C18014C-004

SLR-NMP1-C18018C-002

SLR-NMP1-C18043C-001

SLR-NMP1-C18043C-002

SLR-NMP1-C18045C-005

**Table 2.3.3-7 Electric Steam Boiler System
Components Subject to Aging Management Review**

Component Type	Intended Function
Boiler Casing (Electric Boiler 11)	Leakage Boundary (Spatial)
Bolting (Closure)	Mechanical Closure
Flexible Connection	Leakage Boundary (Spatial)
Heat Exchanger – (Condensate Cooler) Covers	Structural Support
Heat Exchanger – (Condensate Cooler) Nozzles	Leakage Boundary (Spatial)
Heat Exchanger – (Condensate Cooler) Plates	Leakage Boundary (Spatial)
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Tanks (Volume Chamber)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)

The aging management review results for these components are provided in:

**Table 3.3.2-7 Electric Steam Boiler System
Summary of Aging Management Evaluation**

2.3.3.8 **Emergency Diesel Generator System**

Description

The Emergency Diesel Generator (EDG) System provides two sources of electrical power, which are completely separate and are self-contained within the station and therefore not dependent on any outside source. These two standby generators each have adequate capacity to start and carry all of the loads required during a maximum emergency power requirement period. Each diesel engine is connected directly to an AC generator mounted on a common platform (skid). The electrical output from each diesel generator may be connected to one 4160 VAC bus. Each diesel generator is also equipped with intake and exhaust. The EDG System consists of the following plant systems:

- Diesel generator
- Fuel oil handling and storage
- Diesel generator starting air
- Diesel generator lube oil
- Diesel generator cooling water

Each diesel engine contains a DG lube oil system that provides oil at the proper flow, pressure, temperature, and cleanliness to minimize the wear of internal moving parts.

A complete DG fuel oil handling and storage system is installed with each diesel engine to support diesel generator operations.

During engine operation, air must be taken in to support the combustion process, and following combustion, exhaust gases must be removed. An air intake and exhaust system provided with each diesel generator performs these functions.

The DG cooling water system removes heat generated in the engine during the combustion process and by the friction of moving parts. This system cools the cylinder liners, heads, lube oil system, and after coolers. Raw water is pumped from the intake tunnel by diesel generator cooling water pumps located within the Screen and Pump House Building.

The DG starting air system supplies pressurized air to two air-operated starter motors. To facilitate a rapid start, jacket water and lube oil are continually heated and circulated through their respective systems when the engine is shutdown.

Intended Functions

1. Provide motive power to safety-related components. The EDG System is required to power safety-related equipment in the event normal offsite power sources are not available. 10 CFR 54.4(a)(1)
2. Provide heat removal from safety-related heat exchangers. The diesel cooling raw water pumps provide cooling water to the diesel generator engine cooling water heat exchangers. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment

of a safety-related function. The EDG System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. The EDG System also includes nonsafety-related components that maintain mechanical and structural integrity to provide structural support to attached safety-related piping.

10 CFR 54.4(a)(2)

4. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). The EDG System provides power to safe shutdown equipment in the event of a loss of offsite power coincident with the postulated fire.
10 CFR 54.4(a)(3)
5. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The EDG System supplies onsite AC Power during Station Blackout in the recovery phase. 10 CFR 54.4(a)(3)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The emergency diesel generators provide power to ATWS functions, such as the liquid poison system, in the event of loss of normal and reserve ac power. 10 CFR 54.4(a)(3)

UFSAR References

IX.B.4.1

IX.B.6.0

License Renewal Boundary Drawings

SLR-NMP1-C18026-001

SLR-NMP1-C18026-002

SLR-NMP1-C18027-001

**Table 2.3.3-8 Emergency Diesel Generator System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Compressor Housing (Starting Air)	Structural Integrity (Attached)
Expansion Joints	Pressure Boundary
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Lube Oil Coolers) Fins	Heat Transfer
Heat Exchanger – (Lube Oil Coolers) Shell Side Components	Pressure Boundary
Heat Exchanger – (Lube Oil Coolers) Tube Sheet	Pressure Boundary
Heat Exchanger – (Lube Oil Coolers) Tube Side Components	Pressure Boundary
Heat Exchanger – (Lube Oil Coolers) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Raw Water Cooling) Shell Side Components	Pressure Boundary
Heat Exchanger – (Raw Water Cooling) Tube Sheet	Pressure Boundary
Heat Exchanger – (Raw Water Cooling) Tube Side Components	Pressure Boundary
Heat Exchanger – (Raw Water Cooling) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Turbo After Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Turbo Aftercooler) Fins	Heat Transfer
Heat Exchanger – (Turbo Aftercooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Turbo Aftercooler) Tubes	Heat Transfer
	Pressure Boundary
Hoses	Pressure Boundary
Muffler	Pressure Boundary
Piping elements	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)
Pump Casing (Circ Lube Oil)	Pressure Boundary
Pump Casing (Cooling Water Pump)	Pressure Boundary
Pump Casing (Fuel Oil Transfer)	Pressure Boundary
Pump Casing (Motor Driven Fuel Oil)	Pressure Boundary
Pump Casing (Turbo Lube Oil)	Pressure Boundary

Component Type	Intended Function
Silencer	Pressure Boundary
Strainer (Element)	Filter
Tanks (Air Tank)	Pressure Boundary
Tanks (Expansion Tank)	Pressure Boundary
Tanks (Fuel Oil Day Tank)	Pressure Boundary
Tanks (Fuel Oil Storage)	Pressure Boundary
Tanks (Immersion Heater)	Pressure Boundary
Tanks (Intake Filter Oil Reservoir)	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)

The aging management review results for these components are provided in:

Table 3.3.2-8 Emergency Diesel Generator System
Summary of Aging Management Evaluation

2.3.3.9 **Fire Detection and Protection System**

Description

The Fire Detection and Protection (FP) System is a standby system composed of various sub-systems designed to contain and extinguish major fires. Sub-systems include the fire protection water and foam system, the fire protection halon system, the Carbon Dioxide (CO₂) fire protection and manual fire extinguishers. The foam system is abandoned in place. The FP System consists of the following plant systems:

- Fire protection water and foam
- Fire protection, water (above ground, water and foam, for Class 1 seismic)
- Fire protection existing buried transite
- Fire protection, water (underground)
- Fire protection, air fire diesel fire pump starting air from instrument air system to diesel engine
- Transformer fire protection
- Fire protection, halon system
- Carbon dioxide (CO₂) fire protection and generator purging
- Fuel oil handling and storage
- Fuel oil handling and storage (below ground primary and secondary piping)
- Building

The FP System is self-contained, automatic, and self-diagnostic. Operator action is required only to disable certain features for maintenance, testing, or alarm response. It detects and locates a fire, annunciates locally and in the control room, and in certain zones, automatically initiates suppression.

Water for firefighting is furnished by two automatic-starting vertical-turbine fire pumps located in the screenhouse that take suction from the station cooling water intake tunnel. One pump is powered by an electric motor and the other by a diesel engine. A fire main loop supplies water to fixed extinguishing systems, outside hydrants and inside standpipe hose connections.

Total flooding Halon 1301 system is installed to protect several different locations in the plant. Halon is provided by cylinder assemblies located near the protected area.

The CO₂ system supplies carbon dioxide to fixed and hose reel stations for the purpose of fire suppression. The system consists of a carbon dioxide storage tank, valves, and piping required to convey CO₂ to the fixed individual hazards and hose reel stations. The CO₂ system also provides the source of CO₂ for purging the main generator.

Portable fire extinguisher selection and placement is in compliance with the requirements of NFPA 10, Standard for Portable Fire Extinguishers. Adverse effects of portable extinguishing agents have been taken into account in the placement of extinguishers.

The fire barrier functions of components such as fire rated doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire protection function of walls and slabs are also evaluated within this system.

A portion of the FP System charcoal filter deluge system that is open to the emergency

ventilation system through the spray nozzles in the charcoal filters is part of the Reactor Building HVAC System. These safety-related components form part of the ventilation system pressure boundary and are considered part of the secondary containment.

The house service air check valves that are part of the water suppression system are evaluated in the FP System.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Fire Detection and Protection System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the screen and pump house building, turbine building, and reactor building. 10 CFR 54.4(a)(2)
2. Relied upon 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). The Fire Detection and Protection System provides the capability to control postulated fires in plant areas to maintain safe shutdown ability. The diesel driven fire pump is also used to refill the emergency cooling makeup tanks to maintain hot shutdown conditions following a fire. 10 CFR 54.4(a)(3)
3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Fire Detection and Protection System provides a source of water for reactor vessel makeup following an SBO event. 10 CFR 54.4(a)(3)

UFSAR References

X.K
XI.B.1

License Renewal Boundary Drawings

SLR-NMP1-B18040C-002
SLR-NMP1-C18005C-001
SLR-NMP1-C18017C-001
SLR-NMP1-C18022C-001
SLR-NMP1-C18026C-002
SLR-NMP1-C18030C-002
SLR-NMP1-C18030C-003
SLR-NMP1-C18030C-004
SLR-NMP1-C18030C-005
SLR-NMP1-C18030C-006
SLR-NMP1-C18030C-007
SLR-NMP1-C18030C-008
SLR-NMP1-C18030C-009
SLR-NMP1-C18036C
SLR-NMP1-C18039C-001
SLR-NMP1-C18039C-002

SLR-NMP1-C18039C-003
SLR-NMP1-C42355C-001
SLR-NMP1-C42355C-002
SLR-NMP1-C42355C-003
SLR-NMP1-F45094C

**Table 2.3.3-9 Fire Detection and Protection System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Expansion Joints	Pressure Boundary
Fire Barriers (Concrete Curbs)	Fire Barrier
Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier
Fire Barriers (Doors)	Fire Barrier
Fire Barriers (Electrical Raceway)	Fire Barrier
Fire Barriers (For Steel Components)	Fire Barrier
Fire Barriers (Masonry Walls)	Fire Barrier
Fire Barriers (Penetration Seals)	Fire Barrier
Fire Barriers: Damper Housings	Fire Barrier
Fire Hydrant	Pressure Boundary
Flexible Connection	Pressure Boundary
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tubes	Heat Transfer
	Pressure Boundary
Hose Stations	Structural Support
Hoses	Pressure Boundary
Piping elements	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Abandoned Construction Pump)	Leakage Boundary (Spatial)
Pump Casing (Abandoned Pressure Maintenance Pump)	Leakage Boundary (Spatial)
Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary
Pump Casing (Diesel Fuel Oil Transfer Pumps)	Pressure Boundary
Pump Casing (Fire Header Press. Maintenance Pumps)	Leakage Boundary (Spatial)
Pump Casing (Motor Driven Fire Pump)	Pressure Boundary
Pump Casing (U2 Construction Fire Pump)	Leakage Boundary (Spatial)
Silencer / Muffler	Pressure Boundary
Spray Nozzles	Spray
Sprinklers	Pressure Boundary
	Spray
Strainer (Element)	Filter
Tanks (Air Receivers for Diesel Start)	Pressure Boundary
Tanks (CO2 Storage Unit)	Pressure Boundary
Tanks (Day Tank)	Pressure Boundary

Component Type	Intended Function
Tanks (Diesel Storage Tank)	Pressure Boundary
Tanks (Halon)	Pressure Boundary
Tanks (Retard Chambers)	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

Table 3.3.2-9 Fire Detection and Protection System
Summary of Aging Management Evaluation

2.3.3.10 Liquid Poison System

Description

The Liquid Poison (LP) System is a standby system which provides a redundant, independent, and alternate method to bring the nuclear fission reaction to subcriticality and to maintain subcriticality as the reactor cools. The system provides for an orderly and safe shutdown in the event that not enough control rods can be inserted into the reactor core to accomplish shutdown in the normal manner. The LP System is also credited with buffering the pH of the suppression pool following a large break loss of coolant accident (LOCA) to minimize iodine releases from the primary containment. The LP System consists of the following plant systems:

- Liquid poison from tank to positive displacement pumps, and from relief valve discharge to tank
- Liquid poison from pump to outlet external isolation valve
- Liquid poison from reactor to external isolation valve

The system consists of a sodium pentaborate solution storage tank, test water tank, two positive displacement injection pumps, two explosive valves, and associated valves and controls. The LP System injects into the reactor vessel through a sparger attached inside the bottom end of the core shroud which allows the sodium pentaborate to rise upward with the cooling water flow through the reactor fuel. The system is manually initiated from the control room.

The Class 1 portions of the LP System include containment isolation valves and piping. These SSCs are included in the Reactor Coolant Pressure Boundary System. The LP System sparger is included in the Reactor Vessel Internals System.

Intended Functions

1. Introduce emergency negative reactivity to make the reactor subcritical. The Liquid Poison System provides the capability to bring the reactor, at any time in a cycle, from a full power and minimum control rod inventory to a cold, subcritical condition assuming none of the control rods can be inserted. 10 CFR 54.4(a)(1)
2. Control and treat radioactive materials released to the secondary containment. In the event of a large break LOCA, the Liquid Poison System is manually initiated to pump sodium pentaborate into the reactor to maintain suppression pool pH at a level of 7.0 or higher to minimize iodine releases from primary containment. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Liquid Poison System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the Reactor Building. 10 CFR 54.4(a)(2)
4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Liquid Poison System injects sodium pentaborate solution into the reactor to achieve subcriticality independent of rod

insertion. 10 CFR 54.4(a)(3)

5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Liquid Poison System includes environmentally qualified components. 10 CFR 54.4(a)(3)

UFSAR References

IV.B.6.1.2

VII.C

XV.C.5.1.8.1

License Renewal Boundary Drawings

SLR-NMP1-C18006C-001

SLR-NMP1-C18019C

**Table 2.3.3-10 Liquid Poison System
Components Subject to Aging Management Review**

Component Type	Intended Function
Accumulator (Liquid Poison)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Electric Heaters	Pressure Boundary
Gearbox	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Liquid Poison Pump)	Pressure Boundary
Strainer (Element)	Filter
Tanks (Liquid Poison Tank)	Pressure Boundary
Tanks (Pulse Dampener)	Leakage Boundary (Spatial)
Tanks (Test Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-10 Liquid Poison System
Summary of Aging Management Evaluation**

2.3.3.11 **Makeup Demineralizer System**

Description

The Makeup Demineralizer (MD) System consists of the following plant systems:

- Demineralized makeup water
- Demineralizer drains
- Miscellaneous (not contaminated) vent drains and leak-offs
- Miscellaneous not contaminated vents and drains piping
- Yard drainage
- Yard drainage, transformer area

The intended function of the MD System for license renewal is to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid-filled portions of the system located within the reactor building, turbine building and the screen and pump house building. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system. This system is not required to operate to support other license renewal intended functions and is in scope only for potential spatial interaction.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Makeup Demineralizer System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the Reactor Building; Turbine, Waste Handling, and Admin. Structures; and the Screen and Pump House Building. 10 CFR 54.4(a)(2)

UFSAR References

VI.C.2.1
X.G.1
X.G.2
XII.A.2.2

License Renewal Boundary Drawings

SLR-NMP1-C18003C-001
SLR-NMP1-C18003C-002
SLR-NMP1-C18009C-002
SLR-NMP1-C18010C-004
SLR-NMP1-C18016-001
SLR-NMP1-C18016-002
SLR-NMP1-C18019C
SLR-NMP1-C18032C
SLR-NMP1-C18034C-001

SLR-NMP1-C18034C-002
SLR-NMP1-C18034C-003
SLR-NMP1-C18035C
SLR-NMP1-C18036C
SLR-NMP1-C18041C-001
SLR-NMP1-C18041C-002
SLR-NMP1-C18041C-008
SLR-NMP1-C18048C
SLR-NMP1-F45836C-001

**Table 2.3.3-11 Makeup Demineralizer System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump Casing (Makeup Demin. Regen. Waste Pump)	Leakage Boundary (Spatial)
Pump Casing (Temporary Reactor Water Cleanup Fill and Pressure Pump)	Leakage Boundary (Spatial)
Tanks (Anion Bed)	Leakage Boundary (Spatial)
Tanks (Anion Deoxygenation Bed)	Leakage Boundary (Spatial)
Tanks (Cation Bed)	Leakage Boundary (Spatial)
Tanks (Filter)	Leakage Boundary (Spatial)
Tanks (Flush Water Tank)	Leakage Boundary (Spatial)
Tanks (Makeup Demineralized Water Storage Tank)	Leakage Boundary (Spatial)
Tanks (Makeup Demineralizer Regeneration Waste Tank)	Leakage Boundary (Spatial)
Tanks (Mixed Bed)	Leakage Boundary (Spatial)
Tanks (Purifier)	Leakage Boundary (Spatial)
Tanks (Sodium Sulphite Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)

The aging management review results for these components are provided in:

**Table 3.3.2-11 Makeup Demineralizer System
Summary of Aging Management Evaluation**

2.3.3.12 **Radioactive Waste System**

Description

The Radioactive Waste System (RW) System is a normally operating system that collects and processes liquid wastes and solid wastes without limiting normal station operation. The RW system allows for the collection and processing of radioactive waste for disposal, transfer to a vendor for processing and disposal, release of radioactive material in a controlled manner to the environment, and retention of radioactive waste leakage from systems for recovery and reprocessing. The RW System consists of the following plant systems:

- Radioactive liquid waste disposal corrosive service
- Waste disposal system hot water flush
- Miscellaneous contaminated vents, drains and leak off
- Drywell sump discharge piping outside first isolation valve
- Reactor building sump discharge piping
- Radioactive waste disposal (non-corrosive service)
- Radioactive liquid waste
- Thermex waste water processing system
- Sump pump discharge in miscellaneous buildings other than drywell and reactor building
- Miscellaneous line drains in drywell after last valve
- Miscellaneous line drains in reactor building after last valve
- Miscellaneous line drains in turbine building after last valve
- Roof and floor drains (non-radioactive)
- Equipment drains (gravity flow drains, main runs and risers only)
- Polymer solidification system binder, (underground)
- Polymer solidification system binder, (above ground in pump house)
- Polymer solidification system binder, (inside radwaste building and from pump house to radwaste building)
- Polymer solidification system promoter supply
- Polymer solidification system catalyst supply
- Polymer solidification system, flocculent addition
- Polymer solidification system, extender supply
- Drywell sump piping (drywell sump to external isolation valve) I

Gaseous waste processing systems are not addressed in the Radioactive Waste System. Gaseous wastes include airborne particulates as well as gases vented from process equipment. Sources of gaseous waste are from the off-gas system effluent, steam-packing exhaust system effluent, and building ventilation exhausts. Off-gas effluents are processed by the off-gas system which is evaluated in the Condenser Air Removal and Off-gas System. Steam-packing exhaust effluents are processed by the steam-packing exhausting system which is evaluated in the Main Turbine and Auxiliary System. Building ventilation exhausts are evaluated in HVAC systems including the Reactor Building HVAC System, Turbine Building HVAC System, Waste Disposal Building HVAC System, and Radwaste Solidification and Storage Building HVAC System.

The liquid radioactive wastes include all equipment and floor drains in areas of the station which are potentially contaminated with radioactive materials. Additionally, this includes shower waste, laboratory waste, and decontamination area waste. The liquid wastes are handled as one of four types: high-conductivity waste, low-conductivity waste, chemical waste, and miscellaneous waste. Wastes are collected in sumps and transferred to collection tanks for processing. The liquid radwaste portion of the RW System includes primary containment isolation valves associated with the drywell floor drain sump and drywell equipment drain tanks which automatically close on reactor water level low-low or high drywell pressure. Sumps used to collect liquid waste are included and evaluated with their associated structures.

The solid wastes include filter sludge, spent resin, spent condensate filter media, condensate filter backwash sludge, and radioactive tools and equipment. Wastes may be processed or solidified onsite or transferred to a vendor for processing.

The non-radioactive roof and floor drains includes various sump pumps, level switches, piping, and valves used to collect, transfer, and dispose of non-radioactive wastes.

Intended Functions

1. Provide primary containment boundary. The Radioactive Waste System includes piping and primary containment isolation valves that are part of the primary containment boundary. Additionally, the nonsafety-related drywell equipment drain tank and floor drain sump pump discharge piping includes safety-related relief valves to prevent thermal over pressurization of the piping between the pumps discharge check valves and the inboard containment isolation valves. 10 CFR 54.4(a)(1)
2. Provide heat removal from safety-related heat exchangers. The Radioactive Waste System drywell equipment drain tank heat exchangers maintain pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Radioactive Waste System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor building and turbine building. 10 CFR 54.4(a)(2)
4. Relied upon 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). The Radioactive Waste System includes primary containment isolation valves that are classified as high-safety-significant in the Fire PRA. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Radioactive Waste System includes environmentally qualified components. 10 CFR 54.4(a)(3)

UFSAR References

XII.A

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001
SLR-NMP1-C18003C-001
SLR-NMP1-C18003C-002
SLR-NMP1-C18006C-003
SLR-NMP1-C18008C
SLR-NMP1-C18009C-001
SLR-NMP1-C18009C-002
SLR-NMP1-C18016C-001
SLR-NMP1-C18016C-002
SLR-NMP1-C18017C-001
SLR-NMP1-C18020C
SLR-NMP1-C18022C-001
SLR-NMP1-C18022C-002
SLR-NMP1-C18035C
SLR-NMP1-C18036C
SLR-NMP1-C18041C-001
SLR-NMP1-C18041C-002
SLR-NMP1-C18041C-011
SLR-NMP1-C18045C-007
SLR-NMP1-C18045C-009
SLR-NMP1-C18048C

**Table 2.3.3-12 Radioactive Waste System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Expansion Joints	Leakage Boundary (Spatial)
Heat Exchanger – (Cleanup Filter Sludge Tank Blower Aftercooler) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Sheet	Pressure Boundary
Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Side Components	Pressure Boundary
Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary
Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Sheet	Pressure Boundary
Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Side Components	Pressure Boundary
Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tubes	Pressure Boundary
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Condensate Iron Prefilter BWRT Transfer Pump 11 & 12)	Leakage Boundary (Spatial)
Pump Casing (Fuel Pool Filter Sludge Pump)	Leakage Boundary (Spatial)
Tanks (Backwash Receiving Tank Primary and Overflow)	Leakage Boundary (Spatial)
Tanks (Fuel Pool Filter Sludge Tank)	Leakage Boundary (Spatial)
Tanks (Scram Discharge Volume Holding Tank)	Leakage Boundary (Spatial)
Tanks (Waste Surge Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-12 Radioactive Waste System
Summary of Aging Management Evaluation**

2.3.3.13 **Reactor Building Closed Loop Cooling System**

Description

The Reactor Building Closed Loop Cooling (RBCW) System provides demineralized water to cool auxiliary equipment located in the reactor, turbine and waste disposal buildings. The system is designed to cool various combinations of equipment, which may run during different modes of operation. The RBCW System is required to function during normal operating and shutdown mode conditions, as well as during and after operational transients and postulated accidents. The RBCW System consists of the following plant systems:

- Reactor building and waste building closed loop cooling (dearated demineralized water)
- Waste building closed loop cooling (waste building side valves reactor building closed loop cooling return to waste buildings and offgas vacuum pumps)

The RBCW System is a safety-related system that is relied upon to provide cooling to the following major components: fuel pool heat exchangers, instrument air compressors, electric feedwater pumps, condensate pumps, feedwater booster pumps, control room and laboratory air conditioning equipment, recirculation pump coolers, cleanup system nonregenerative heat exchangers, reactor building equipment drain tank cooler, drywell air coolers, waste disposal system heat exchangers, shutdown cooling system heat exchangers and pump coolers, and offgas vacuum pump coolers. RBCW piping, to and from the recirculation pump coolers, and drywell air coolers are provided with containment isolation valves.

The RBCW System is credited with being able to provide makeup water to the control room A/C chilled water expansion tank during normal and emergency conditions with a complete loss of offsite power. This in turn provides cooling to the control room.

The major system components include three horizontal centrifugal pumps, three RBCW heat exchangers, and the necessary piping, valves, instruments, and components to supply the cooling water to the stated loads. The cooling water for the RBCW System heat exchangers is supplied by the Service Water System utilizing two normal service water pumps backed up by two emergency service water pumps. The RBCW System acts as an intermediate cooling loop between various plant systems, which may contain radioactive fluids and the Service Water System in order to prevent the release of potentially radioactive fluids to the environment.

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The Reactor Building Closed Loop Cooling System provides cooling to multiple safety-related heat exchangers. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Reactor Building Closed Loop Cooling System includes containment isolation valves associated with the cooling water supply and return for the reactor recirculation pump coolers and drywell air coolers. 10 CFR 54.4(a)(1)

3. Maintain emergency temperature limits within areas containing safety-related components. The Reactor Building Closed Loop Cooling System is credited with being able to provide makeup water to the control room HVAC chilled water expansion tank during normal and emergency conditions with a complete loss of offsite power. 10 CFR 54.4(a)(1)
4. Provide centralized area for control and monitoring of nuclear safety-related equipment. The Reactor Building Closed Loop Cooling System is credited with being able to provide makeup water to the control room HVAC chilled water expansion tank during normal and emergency conditions with a complete loss of offsite power. 10 CFR 54.4 (a)(1)
5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Building Closed Loop Cooling System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor and turbine buildings. The Reactor Building Closed Loop Cooling System also includes nonsafety-related components that maintain mechanical and structural integrity to provide structural support to attached safety-related piping. 10 CFR 54.4(a)(2)
6. Relied upon 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). The Reactor Building Closed Loop Cooling System is credited to reach and maintain safe and stable conditions by providing cooling to the control room HVAC. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Reactor Building Closed Loop Cooling System includes environmentally qualified components. 10 CFR 54.4(a)(3)

UFSAR References

X.D.1
X.D.2
Table VI-3b
Figure X-4

License Renewal Boundary Drawings

SLR-NMP1-C18005C-001
SLR-NMP1-C18006C-003
SLR-NMP1-C18008C
SLR-NMP1-C18009C-001
SLR-NMP1-C18009C-002
SLR-NMP1-C18011C-002
SLR-NMP1-C18014C-001
SLR-NMP1-C18018C-001
SLR-NMP1-C18018C-002
SLR-NMP1-C18020C-001

SLR-NMP1-C18022C-001
SLR-NMP1-C18022C-002
SLR-NMP1-C18022C-003
SLR-NMP1-C18022C-004
SLR-NMP1-C18041C-002
SLR-NMP1-C18041C-007
SLR-NMP1-C18045C-007
SLR-NMP1-C18047C-001

**Table 2.3.3-13 Reactor Building Closed Loop Cooling System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (RBCW Heat Exchangers) Shell Side Components	Pressure Boundary
Heat Exchanger – (RBCW Heat Exchangers) Tube Sheet	Pressure Boundary
Heat Exchanger – (RBCW Heat Exchangers) Tube Side Components	Pressure Boundary
Heat Exchanger – (RBCW Heat Exchangers) Tubes	Heat Transfer
	Pressure Boundary
Piping elements	Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)
Pump Casing (Reactor Building Cooling Water Pumps)	Pressure Boundary
Strainer (Element)	Filter
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary
	Structural Integrity (Attached)

The aging management review results for these components are provided in:

**Table 3.3.2-13 Reactor Building Closed Loop Cooling System
Summary of Aging Management Evaluation**

2.3.3.14 **Reactor Building HVAC System**

Description

The Reactor Building HVAC (RBV) System is a normally operating system designed to provide a continuous flow of filtered air throughout the reactor building while maintaining a negative pressure to minimize out-leakage. The RBV System includes two separate ventilation systems. One system is used during normal operation while the other is a standby system that is used under accident conditions.

The normal ventilation system provides clean fresh air to the reactor building, removes air from areas where excessive heat concentration and potential airborne contamination exist, and maintains a negative pressure in the reactor building relative to the atmosphere by regulating the amount of outside air introduced into the building. The system supply fans draw air through a louvered, screened penthouse, an electric heating coil, a filter and two parallel connected flow valves to supply air to the building distribution ductwork via one of two redundant supply fans. The common discharge header directs flow through two isolation valves and into the reactor building via distribution ducts. The system includes local electric heating units and service water-cooled heat exchanger units throughout the building as required to maintain desired temperatures.

Both the main supply and exhaust ducts are equipped with two leak-tight isolation valves in series, which close automatically upon receipt of a high radiation signal from radiation monitors in the exhaust ductwork or from high radiation at the refueling platform during refueling operations. The supply and exhaust fans trip immediately. The closure sequence of the normal supply and exhaust isolation valves ensures that reactor building negative pressure is maintained during the transition from normal to emergency ventilation. They also may be controlled manually from the main control room.

The emergency ventilation system is a standby system designed to filter particulates and iodines from the reactor building atmosphere. The system automatically initiates upon receipt of a high radiation signal from radiation monitors in the exhaust ductwork or from high radiation at the refueling platform during refueling operations. The system consists of two identical trains, each consisting of an exhaust fan, two high efficiency filters, a charcoal filter, an electric heater, a flow control valve, and ductwork. The system takes its suction from the reactor building exhaust upstream of the isolation valves and exhausts through the stack.

Additionally, the emergency ventilation system can be used as a purge path for the primary containment atmosphere to prevent a combustible hydrogen-oxygen concentration from accumulating immediately following or during a loss of coolant accident (LOCA).

The RBV System includes a portion of the Fire Detection and Protection System charcoal filter deluge system that is open to the emergency ventilation system through the spray nozzles in the charcoal filters. These safety-related components form part of the ventilation system pressure boundary and are considered part of the secondary containment.

Intended Functions

1. Control and treat radioactive materials released to the secondary containment. The Reactor Building HVAC System removes and filters particulates and iodine from the reactor building atmosphere prior to exhausting to the stack during secondary containment isolation conditions. 10 CFR 54.4(a)(1)
2. Control combustible gas mixtures in the primary containment atmosphere. The combustible gas control system utilizes the emergency ventilation system as a purge path for primary containment atmosphere to prevent a combustible hydrogen-oxygen concentration from accumulating in the primary containment atmosphere immediately following or during a LOCA. 10 CFR 54.4(a)(1)
3. Provide secondary containment boundary. The Reactor Building HVAC System includes a portion of the charcoal filter deluge system that is open to the emergency ventilation system through the spray nozzles in the charcoal filters. These safety-related components form part of the ventilation system pressure boundary and are considered part of secondary containment. 10 CFR 54.4(a)(1)
4. Resists nonsafety-related SSC failure that could prevent satisfactory accomplishment of safety-related function. The Reactor Building HVAC System contains nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor building (service water area coolers). 10 CFR 54.4(a)(2).
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Reactor Building HVAC System includes environmentally qualified components. 10 CFR 54.4(a)(3).
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Reactor Building HVAC System is credited in the ATWS evaluation to remove and filter particulates and iodine from the reactor building atmosphere. 10 CFR 54.4(a)(3)

UFSAR References

UFSAR Section VI.E.2 .2

UFSAR VII.G.3.1

UFSAR Section VII.H.1.0

License Renewal Boundary Drawings

SLR-NMP1-C18010C-001

SLR-NMP1-C18013C

SLR-NMP1-C18027C-002

SLR-NMP1-C18030C-004

**Table 2.3.3-14 Reactor Building HVAC System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Bolting (Ducting Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Flexible Connection	Pressure Boundary
Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Area Coolers) Tubes	Leakage Boundary (Spatial)
Piping, piping components	Pressure Boundary
Valve Body	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-14 Reactor Building HVAC System
Summary of Aging Management Evaluation**

2.3.3.15 **Reactor Water Cleanup**

Description

The Reactor Water Cleanup (RWCU) System is designed to maintain high reactor water purity by recirculating a portion of the reactor coolant through filters and demineralizers to remove particulate and dissolved impurities. The RWCU System minimizes deposits on fuel surfaces and reduces the secondary sources of beta and gamma radiation resulting from the deposition of corrosion products, fission products, and impurities in the primary system. The RWCU System can be operated during startup, shutdown, and refueling modes, as well as during normal power operation. The RWCU System is in scope for license renewal however, nonsafety-related liquid filled portions of the system located within certain rooms and equipment vaults do not have the potential for spatial interaction and are not in scope. The RWCU System includes the following plant systems:

- Modified reactor water cleanup system noble chemical injection system monitoring equipment
- Reactor cleanup, reactor to pressure control valve and cleanup recirculation pump to reactor
- Modified reactor cleanup system, 6 inch and 4 inch sizes, suction side, high-pressure piping outside drywell
- Modified reactor cleanup system, suction and discharge inside drywell
- Reactor cleanup, pressure control valve to pumps
- Reactor miscellaneous connections, reactor valve and drain to last isolation valve
- Reactor drain to reactor clean-up suction
- Reactor cleanup system, safety valve discharge to check valve at torus
- Reactor cleanup safety valve discharge, torus to check valve
- Reactor cleanup safety valve discharge, vacuum breaker

The RWCU System includes two, full-size filters and demineralizers. The cleanup filters are pressure-precoat type and the demineralizers are of the mixed-bed resin type. Water is normally removed at reactor pressure from one of the reactor recirculation loops and from the reactor bottom head drain line and cooled in the tube side of the regenerative heat exchanger and non-regenerative heat exchangers, reduced in pressure, filtered, demineralized, and pumped through the shell side of the regenerative heat exchanger to the reactor through the feedwater system. Whenever reactor pressure is insufficient to maintain suction pressure at the main cleanup pumps, an auxiliary pump is used.

The RWCU System includes hydrogen water chemistry (HWC) and noble metal chemical addition (NMCA or NobleChem) monitoring systems. The monitoring systems include two electrochemical corrosion potential (ECP) monitoring locations, material coupons (durability monitor) for monitoring the noble chemistry coating thickness, the capability for crack growth rate monitoring, and a sample supply for the NMCA temporary equipment needed for the injection of the NMCA material.

The RWCU System includes area temperature instrumentation to detect reactor water cleanup system leaks or breaks in system piping outside of the primary containment. Upon detection of a leak or break, the system generates input signals to the Reactor Protection System (RPS) which generates trip signals that initiate closure of the RWCU

System isolation valves, thereby isolating the leak/break from the reactor coolant pressure boundary. Additional automatic system isolations include a reactor low-low water level signal from RPS, RWCU System low flow or high-pressure, or Liquid Poison System initiation.

The Class 1 portion of the RWCU System includes primary containment isolation valves and piping. These SSCs are included in the Reactor Coolant Pressure Boundary System.

Intended Functions

1. Provide primary containment boundary. The Reactor Water Cleanup System includes safety-related containment isolation check valves associated with the system relief valve discharge into the torus. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Reactor Water Cleanup System includes area temperature instrumentation that, upon detection of a leak or break, generates input signals to the RPS which generates trip signals that initiate closure of the reactor water cleanup system primary containment isolation valves. 10 CFR 54.4(a)(1)
3. Provide heat removal from safety-related heat exchangers. The Reactor Water Cleanup System heat exchangers maintain pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)
4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Reactor Water Cleanup System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. 10 CFR 54.4(a)(2)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Reactor Water Cleanup System includes components which are environmentally qualified. 10 CFR 54.4(a)(3)
6. Relied upon 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). The Reactor Water Cleanup System includes a system block valve credited to support inventory control. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram (10 CFR 50.62). The Reactor Water Cleanup System automatically isolates when the Liquid Poison System is initiated to prevent removal of the sodium pentaborate in the reactor. 10 CFR 54.4(a)(3)

UFSAR References

X.B
Table VIII-4

Table VI-3a

License Renewal Boundary Drawings

SLR-NMP1-C18006C-001
SLR-NMP1-C18006C-002
SLR-NMP1-C18009C-001
SLR-NMP1-C18009C-002
SLR-NMP1-C18009C-003
SLR-NMP1-C18034C-002
SLR-NMP1-C18022C-002
SLR-NMP1-C18035C
SLR-NMP1-C18041C-002
SLR-NMP1-C18048C

**Table 2.3.3-15 Reactor Water Cleanup
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (Auxiliary Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Auxiliary Cleanup Pump Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Auxiliary Cleanup Pump Oil Cooler) Tubes	Pressure Boundary
Heat Exchanger – (Auxiliary Cleanup Pump Pedestal Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Cleanup Filter Precoat Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Cleanup Filter Precoat Cooler) Tubes	Pressure Boundary
Heat Exchanger – (Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Cleanup Pump Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Cleanup Pump Oil Cooler) Tubes	Pressure Boundary
Heat Exchanger – (Non Regenerative) Shell Side Components	Pressure Boundary
Heat Exchanger – (Non Regenerative) Tube Sheet	Pressure Boundary
Heat Exchanger – (Non Regenerative) Tube Side Components	Pressure Boundary
Heat Exchanger – (Non Regenerative) Tubes	Pressure Boundary
Heat Exchanger – (Regenerative) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Regenerative) Tube Side Components	Leakage Boundary (Spatial)
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Piping, piping components greater than or equal to 4 NPS	Leakage Boundary (Spatial)

Component Type	Intended Function
Pump Casing (Auxiliary Cleanup Pump)	Leakage Boundary (Spatial)
Pump Casing (Cleanup Pump)	Leakage Boundary (Spatial)
Pump Casing (Filter Aid Pump)	Leakage Boundary (Spatial)
Pump Casing (Precoat Pump)	Leakage Boundary (Spatial)
Pump Casing (Sludge Pump)	Leakage Boundary (Spatial)
Tanks (Cleanup Demineralizer)	Leakage Boundary (Spatial)
Tanks (Cleanup Pump Oil Reservoir)	Leakage Boundary (Spatial)
Tanks (Cleanup Pump Pac Loc Reservoir)	Leakage Boundary (Spatial)
Tanks (Cleanup Pump Surge Tank)	Leakage Boundary (Spatial)
Tanks (Filter Aid Mix Tank)	Leakage Boundary (Spatial)
Tanks (Filter Precoat Mix Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

Table 3.3.2-15 Reactor Water Cleanup
Summary of Aging Management Evaluation

2.3.3.16 Sampling System

Description

The Sampling System is designed to provide useful samples of various process fluids and containment atmosphere streams under all conditions ranging from normal shutdown and power operations to a loss of coolant accident (LOCA). The Sampling System is comprised of the following plant systems:

- Samples
- Samples (after source valves)
- Condenser offgas and stack gas samples
- Post accident sampling system
- Nitrogen supply

The system obtains highly radioactive samples of reactor coolant, liquid radwaste effluent, suppression pool, containment atmosphere streams, and provides information for making corrections or adjustments to process system operations. Also, this system provides stack effluent monitoring and input signals to reactor protection system logic for containment vent and purge (stack) isolation. Continuous monitoring and manual sampling are utilized.

The Class 1 portion of the Sampling System includes primary containment isolation valves and piping. These SSCs are included in the Reactor Coolant Pressure Boundary System.

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The Sampling System heat exchangers maintain pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Sampling System contains portions of piping that maintain Reactor Building Closed Loop Cooling System pressure boundary. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Sampling System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. 10 CFR 54.4(a)(2)
4. Relied upon 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). The Sampling System includes a block valve credited for Fire Protection. 10 CFR 54.4(a)(3)

UFSAR References

VIII.C.3

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001
SLR-NMP1-C18005C-002
SLR-NMP1-C18006C-001
SLR-NMP1-C18009C-001
SLR-NMP1-C18009C-003
SLR-NMP1-C18020C
SLR-NMP1-C18022C-002
SLR-NMP1-C18041C-001
SLR-NMP1-C18041C-002
SLR-NMP1-C18041C-004
SLR-NMP1-C18041C-007
SLR-NMP1-C18041C-008
SLR-NMP1-C18041C-011

**Table 2.3.3-16 Sampling System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Drip Pan	Leakage Boundary (Spatial)
Heat Exchanger – (Noble Chem HWC Sample Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Noble Chem HWC Sample Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Noble Chem HWC Sample Cooler) Tubes	Pressure Boundary
Heat Exchanger – (Sample Coolers) Shell Side Components	Leakage Boundary (Spatial)
	Pressure Boundary
Heat Exchanger – (Sample Coolers) Tubes	Pressure Boundary
Hoses	Leakage Boundary (Spatial)
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Post Accident Sample Pumps)	Leakage Boundary (Spatial)
Pump Casing (Tunnel Sample Pumps)	Leakage Boundary (Spatial)
Tanks (Sampling Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-16 Sampling System
Summary of Aging Management Evaluation**

2.3.3.17 Service Water System

Description

The Service Water (SW) System is a normally operating system that provides cooling to various heat exchangers and coolers throughout the plant. The SW System consists of the following plant systems:

- Service water system
- Service water to administration building basement air conditioner system
- Lawn sprinkler system
- Chemical injection system to service water pump forebay.

The plant service water system consists of both a nonsafety-related system and a safety-related system. The nonsafety-related plant service water system provides lake water for cooling the reactor building closed loop cooling water (RBCW) and turbine building closed loop cooling water (TBCW) system heat exchangers, and other plant heat loads. Service water also is supplied to the administration building basement air conditioner system and lawn sprinkler system which are not in scope for license renewal. The nonsafety-related service water system consists of two full-capacity pumps, strainers, and associated valves and piping. The reactor building service water return and turbine building service water return lines are monitored for radiation prior to discharge. There are no system isolations associated with the radiation monitoring function.

The safety-related plant service water system (i.e., emergency service water system) provides cooling water to the RBCW heat exchangers on a loss of both normal and reserve AC power or malfunction of the SW pumps, ensuring the RBCW heat exchangers provide adequate cooling for safety-related and essential loads. The safety-related emergency service water system consists of two full-capacity emergency service water pumps supplied by emergency AC power. Each of the emergency service water pumps is connected to one of the service water supply lines to the RBCW heat exchangers in the reactor building. Each emergency service water pump can supply water to any one of the three heat exchangers.

The nonsafety-related plant service water system provides cooling water to the TBCW heat exchangers, which provide cooling water to instrument air compressor #13, which performs an a(3) credited function to support the fire protection regulated event.

The chemical injection system to service water pump forebay system pumps chemicals from the circulating water system chemical tanks to the service water pump intakes.

Traveling screens are evaluated in the Circulating Water System. Trash racks are evaluated in the Screen and Pump House Building.

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The Service Water System provides cooling to the safety-related reactor building closed cooling water heat exchangers. Additionally, the Service Water System provides a discharge flow path for the containment spray raw water system. 10 CFR 54.4(a)(1)

2. Provide primary containment boundary. The Service Water System includes manual primary containment isolation valves for system piping that enters the free space of the containment. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Service Water System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the Screen and Pump House, Reactor Building, and Turbine Building. In addition, nonsafety-related SSCs are required to complete the service water flowpath from the RBCW heat exchangers out through the discharge tunnel. 10 CFR 54.4(a)(2)
4. Relied upon 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). The Service Water System is credited to reach and maintain safe and stable conditions by providing cooling to the reactor building closed cooling water and turbine building closed cooling water heat exchangers. 10 CFR 54.4(a)(3).

UFSAR References

X.F.1
X.F.2
Table VI-3b
Figure X-6

License Renewal Boundary Drawings

SLR-NMP1-B26941C-001
SLR-NMP1-C18006C-003
SLR-NMP1-C18010C-005
SLR-NMP1-C18011C-001
SLR-NMP1-C18014C-004
SLR-NMP1-C18018C-002
SLR-NMP1-C18022C-001
SLR-NMP1-C18022C-002
SLR-NMP1-C18022C-003
SLR-NMP1-C18022C-005
SLR-NMP1-C18027C-001
SLR-NMP1-C18027C-002
SLR-NMP1-C18027C-003
SLR-NMP1-C18029C-001
SLR-NMP1-C18034C-001
SLR-NMP1-C18034C-003
SLR-NMP1-C18036C
SLR-NMP1-C33211C

**Table 2.3.3-17 Service Water System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Heat Transfer
	Pressure Boundary
Hoses	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Piping, piping components: Insulated	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Chlorine Monitor Sample Pump)	Leakage Boundary (Spatial)
Pump Casing (Demineralizer Feed Pumps)	Leakage Boundary (Spatial)
Pump Casing (Emergency Service Water Pumps)	Pressure Boundary
Pump Casing (Filter Backwash)	Leakage Boundary (Spatial)
Pump Casing (SW Dispersant)	Leakage Boundary (Spatial)
Pump Casing (Service Water Discharge Radiation Monitor)	Leakage Boundary (Spatial)
Pump Casing (Service Water Pumps)	Pressure Boundary
Pump Casing (Trasar Panel Booster Pump)	Leakage Boundary (Spatial)
Strainer (Element) (Emergency and Normal Service Water Pump Discharge Strainers)	Filter
Tanks (Clearwell)	Leakage Boundary (Spatial)
Tanks (Precipitator)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary
Valve Body: Insulated	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-17 Service Water System
Summary of Aging Management Evaluation**

2.3.3.18 **Shutdown Cooling System**

Description

The Shutdown Cooling (SDC) System provides for the removal of reactor fission product decay heat during shutdown operations by circulating water from the reactor through heat exchangers and back to the reactor. The SDC System consists of the following plant system:

- Reactor Shutdown Cooling (350 degrees Fahrenheit After External Isolation Valve)

The SDC System consists of three heat exchangers, three pumps and associated controls, instrumentation, motors, and valves. Two heat exchangers and pumps are sufficient to cool and maintain the reactor water temperature during shutdown. The initial phase of a normal reactor coolant system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser with the main condenser acting as a heat sink. At lowered reactor pressures and temperatures, the SDC System is manually actuated from the control room. The reactor water enters this system from the suction line of one of the reactor recirculation pumps and initially flows through two partial-capacity shutdown cooling loops, (a third loop is available if needed) which then discharges into the discharge line of a different reactor recirculation pump. The heat exchangers are cooled by the Reactor Building Closed Loop Cooling Water System. Additionally, the SDC System can provide cooling to the reactor head cavity.

The Class 1 portion of the SDC System includes primary containment isolation valves and piping. These SSCs are included in the Reactor Coolant Pressure Boundary System.

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The Shutdown Cooling System heat exchangers maintain pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Shutdown Cooling System supports containment isolation by providing a water seal to the shutdown cooling isolation valves. 10 CFR 54.4(a)(1)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Shutdown Cooling System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. 10 CFR 54.4(a)(2)
4. Relied upon 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). The Shutdown Cooling System contains components that support the various analyses related to the NFPA 805 transition including Non-Power Operation. 10 CFR 54.4(a)(3)

5. Relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Shutdown Cooling System will be used after the second emergency diesel generator or off-site AC power is restored. 10 CFR 54.4(a)(3)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients Without Scram. The Shutdown Cooling System ultimately cools the reactor if the main steam isolation valves cannot be reopened after closure to establish flow to the main condenser. 10 CFR 54.4(a)(3)

UFSAR References

VII.A
X.A
X.J
X.K

License Renewal Boundary Drawings

SLR-NMP1-C18006C-001
SLR-NMP1-C18007C-002
SLR-NMP1-C18018C-001
SLR-NMP1-C18018C-002
SLR-NMP1-C18022C-002
SLR-NMP1-C18041C-002

**Table 2.3.3-18 Shutdown Cooling System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Shutdown Cooling Pump) Shell Side Components	Pressure Boundary
Heat Exchanger – (Shutdown Cooling Pump) Tube Side Components	Pressure Boundary
Heat Exchanger – (Shutdown Cooling Pump) Tubes	Pressure Boundary
Heat Exchanger – (Shutdown Cooling) Shell Side Components	Pressure Boundary
Heat Exchanger – (Shutdown Cooling) Tube Sheet	Pressure Boundary
Heat Exchanger – (Shutdown Cooling) Tube Side Components	Pressure Boundary
Heat Exchanger – (Shutdown Cooling) Tubes	Heat Transfer
	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Shutdown Cooling Pump)	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-18 Shutdown Cooling System
Summary of Aging Management Evaluation**

2.3.3.19 **Spent Fuel Pool Cooling and Storage System**

Description

The Spent Fuel Pool Cooling and Storage (FPC) System is a normally operating system designed to maintain water inventory in the spent fuel pool and to remove the decay heat from spent fuel assemblies and impurities from the pool water in order to maintain water temperature and purity within acceptable limits, ensuring clarity under all anticipated conditions.

The FPC System is normally operated as a closed loop system taking suction from the spent fuel storage pool surge tanks and returning the water to the pool via diffusers. Following refueling operations, the FPC System can be used to drain the reactor internals storage pit and head cavity. Alternate lines allow transport of the water to either the main condenser or the Radioactive Waste System as needed.

The FPC System contains two pumps that are externally sealed that take suction from two skimmer surge tanks and circulate the pool water through two parallel loops, each consisting of one precoat type filter and one heat exchanger. The water is returned to the pool through diffusers. One circulation loop, consisting of a pump, filter, and heat exchanger, is adequate to handle the heat load imposed by the system during normal spent-fuel storage. The other (second) circulation loop acts as a standby and is available to operate in parallel to provide the cooling and filtering required for full core offload fuel storage. Flow control valves regulate the flow in each loop. Cooling water is supplied to the heat exchangers from the Reactor Building Closed Loop Cooling Water System. A sample point is incorporated to determine any tube leakage. The cooling and filtering functions of FPC are nonsafety-related. The portions of the FPC System that provide make-up water and ensure the integrity of the spent fuel pool pressure boundary are safety-related (i.e., portions that ensure the fuel remains covered by water).

The FPC System utilizes two types of spent fuel storage racks in the spent fuel storage pool, boral racks and boraflex racks. Both are designed to maintain an adequate criticality margin (Keff less than 0.95) under all storage conditions. The spent fuel pool is currently licensed for 4,086 fuel assemblies. New fuel storage racks, spent fuel pool, and liners are evaluated with the Reactor Building structure.

Intended Functions

1. Ensure adequate cooling in the spent fuel pool to maintain stored fuel within acceptable temperature limits. This function is provided by portions of the FPC System that maintain the integrity of the spent fuel pool pressure boundary and provide make-up water to maintain adequate water inventory. 10 CFR 54.4(a)(1)
2. Prevents criticality of fuel assemblies stored in the spent fuel pool. The spent fuel storage racks maintain an adequate criticality margin (Keff less than 0.95) under all storage conditions. 10 CFR 54.4 (a)(1)
3. Provide heat removal from safety-related heat exchangers. The Spent Fuel Pool Cooling heat exchangers maintain the pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)

4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Includes nonsafety-related SSCs that are functionally relied upon to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or (b) directly mitigate the consequences of a design basis event (DBE). FPC components assist in maintaining a post-loss of coolant accident negative secondary containment pressure by maintaining spent fuel pool temperature below a specified value, thereby limiting the amount of heat transferred from the spent fuel pool to the reactor building environment. 10 CFR 54.4 (a)(2)
5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Spent Fuel Pool Cooling and Storage System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. 10 CFR 54.4(a)(2)
6. Relied upon 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). Provides decay heat removal and inventory control when reactor coolant system temperature is less than 212 degrees Fahrenheit and when the fuel is offloaded to the spent fuel pool during a refueling outage in a non-power operational fire event. 10 CFR 54.4(a)(3)

UFSAR References

X.H
X.J

License Renewal Boundary Drawings

SLR-NMP1-C18008C
SLR-NMP1-C18036
SLR-NMP1-C18041C-002

**Table 2.3.3-19 Spent Fuel Pool Cooling and Storage System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Fuel Storage Racks (Spent Fuel Storage Racks)	Absorb Neutrons
	Structural Support
Heat Exchanger – (Fuel Pool) Shell Side Components	Pressure Boundary
Heat Exchanger – (Fuel Pool) Tube Sheet	Pressure Boundary
Heat Exchanger – (Fuel Pool) Tube Side Components	Pressure Boundary
Heat Exchanger – (Fuel Pool) Tubes	Heat Transfer
	Pressure Boundary
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Body Feed Pump)	Pressure Boundary
Pump Casing (Circulating Pump)	Pressure Boundary
Pump Casing (Precoat Pump)	Pressure Boundary
Strainer (Element)	Filter
Tanks (Body Feed Filter Aid Mix Tank)	Leakage Boundary (Spatial)
Tanks (Fuel Pool Filter)	Pressure Boundary
Tanks (Precoat Tank)	Leakage Boundary (Spatial)
Tanks (Surge Tank)	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System
Summary of Aging Management Evaluation**

2.3.3.20 Turbine Building Closed Loop Cooling System

Description

The Turbine Building Closed Loop Cooling (TBCW) System provides demineralized water to cool auxiliary equipment located in the turbine building. The system is designed to cool various combinations of equipment, which may run during different modes of operation. The TBCW System is required to function during normal operating and shutdown mode conditions.

The TBCW System is a nonsafety-related system that is relied upon to provide cooling to the following major components: shaft-driven reactor feedwater pump, turbine oil tank coolers, steam packing exhausters coolers, mechanical vacuum pump coolers, generator hydrogen coolers, generator stator coolers, generator lead coolers, recirculating pump motor-generator (mg) set coolers, the house service air compressor, sample system coolers, turbine building equipment drain tank #11, instrument air compressor #13, instrument air dryer #12, battery room #14 air conditioner, and the condensate filtration system air compressor.

The major system components include two centrifugal pumps, three TBCW heat exchangers, and the necessary piping, valves, instruments, and components to supply the cooling water to the stated loads. Additionally, the system contains a makeup tank that services both the TBCW System and Reactor Building Closed Loop Cooling System by providing makeup water to ensure both systems are filled during operation. The cooling water for the TBCW System heat exchangers is supplied by the Service Water System. The TBCW System acts as an intermediate cooling loop between various plant systems, which may contain radioactive fluids, and the Service Water System in order to prevent the release of potentially radioactive fluids to the environment.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Turbine Building Closed Loop Cooling System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the turbine building. 10 CFR 54.4(a)(2).
2. Relied upon 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). The Turbine Building Closed Loop Cooling System provides cooling water to the instrument air compressor and is credited to support the analyses related to NFPA 805 non-power operation. 10 CFR 54.4(a)(3).

UFSAR References

X.E.1

X.E.2

Figure X-5

License Renewal Boundary Drawings

SLR-NMP1-C18003C-002

SLR-NMP1-C18005C-001
SLR-NMP1-C18011C-001
SLR-NMP1-C18011C-002
SLR-NMP1-C18022C-001
SLR-NMP1-C18022C-003
SLR-NMP1-C18034C-001
SLR-NMP1-C18041C-001
SLR-NMP1-C18041C-011
SLR-NMP1-F45836C-001

**Table 2.3.3-20 Turbine Building Closed Loop Cooling System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (TBCW Heat Exchanger 11) Shell Side Components	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 11) Tube Sheet	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 11) Tube Side Components	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 12) Shell Side Components	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 12) Tube Sheet	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 12) Tube Side Components	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 13) Shell Side Components	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 13) Tube Sheet	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 13) Tube Side Components	Pressure Boundary
Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Heat Transfer
	Pressure Boundary
Hoses	Leakage Boundary (Spatial)
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Piping, piping components: Insulated	Leakage Boundary (Spatial)
Pump Casing (Chiller H2O Circulating Pump): Insulated	Leakage Boundary (Spatial)
Pump Casing (Circulating Pump)	Leakage Boundary (Spatial)
Pump Casing (Turbine Building Cooling Water Pumps)	Pressure Boundary
Tanks (Closed Loop Cooling System Makeup Tank)	Leakage Boundary (Spatial)
Tanks (Surge Tank): Insulated	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)

Component Type	Intended Function
Valve Body	Pressure Boundary

The aging management review results for these components are provided in:

Table 3.3.2-20 Turbine Building Closed Loop Cooling System
Summary of Aging Management Evaluation

2.3.3.21 **Turbine Building HVAC System**

Description

The Turbine Building HVAC (TBV) System is a normally operating system designed to provide a continuous flow of filtered air throughout the building while maintaining a negative pressure to control the release of contaminated air and prevent out leakage. The TBV System consists of the following plant systems:

- Turbine building ventilation exhaust
- Diesel generator building ventilation

The TBV System includes air intakes, filters, electric heating units, flow control dampers, dampers, and ductwork to distribute air to various areas of the turbine building. Outside air enters via louvered, screened penthouses, passing through filters and heating coils. Exhaust air returns through a plenum to the stack for discharge and is monitored (alarm only) for radiation. The system also includes water-cooled heat exchanger cooling units in areas where equipment operating at a high temperature are located in order to dissipate the radiant heat loss from this equipment and to maintain desired temperatures for personnel comfort and equipment protection.

The diesel generator building ventilation includes two safety-related roof exhaust fans and a roll-up door for each diesel generator room. The fans and the roll-up door operate together to maintain the diesel room temperature below maximum temperatures for operation of the diesel. Thermostatically controlled electric heaters are provided to maintain the required ambient room temperature to support diesel readiness.

Smoke and heat removal capability is provided for three smoke zones in the turbine building. These systems have sufficient smoke exhaust fans, isolation dampers, and controls dedicated to smoke removal. Smoke removal for the upper elevation of the turbine building is provided by motor-operated vents installed in the turbine building roof and five sidewall vents.

The TBV System also includes safety-related blocking valves, backdraft dampers, and ductwork in the turbine building ventilation, off-gas building ventilation, waste disposal building ventilation, waste disposal building extension ventilation and radwaste solidification and storage building ventilation plant systems. These blocking valves and backdraft dampers prevent backflow from the other ventilation systems that also exhaust into the safety-related stack plenum. This prevents ground level radioactive releases when the ventilation system exhaust fans are not operating.

The TBV System includes fire dampers. These are evaluated in the Fire Detection and Protection System.

Intended Functions

1. Provide secondary containment boundary. The Turbine Building HVAC System includes safety-related blocking valves and backdraft dampers to prevent backflow from the exhaust plenum ensuring that releases from the secondary containment ventilation system are through the stack via the exhaust plenum and would not be released at ground level through the Turbine Building HVAC System.

10 CFR 54.4(a)(1)

2. Maintain emergency temperature limits within areas containing safety-related components. The Turbine Building HVAC System includes safety-related roof exhaust fans and roll-up doors in the emergency diesel generator rooms which operate together to ensure the room temperature remains below the emergency diesel generator qualification temperature. 10 CFR 54.4(a)(1)
3. Resists nonsafety-related SSC failure that could prevent satisfactory accomplishment of safety-related function. The Turbine Building HVAC System contains nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the turbine building (service water area coolers). 10 CFR 54.4(a)(2)
4. Relied upon 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). The diesel generator building roof exhaust fans are credited for fire safe shutdown. The system is also credited for smoke removal in the Turbine Building. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Turbine Building HVAC System includes environmentally qualified components. 10 CFR 54.4(a)(3)

UFSAR References

III.A.1.4
III.A.2.2
III.A.2.3
III.C2.2
III.D.2.2
III.I.2.2

License Renewal Boundary Drawings

SLR-NMP1-C18010C-001
SLR-NMP1-C18021C-001
SLR-NMP1-C18021C-002
SLR-NMP1-C18021C-003
SLR-NMP1-C18022C-003
SLR-NMP1-C18027C-001
SLR-NMP1-C18027C-003

**Table 2.3.3-21 Turbine Building HVAC System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Bolting (Ducting Closure)	Mechanical Closure
Ducting and Components	Pressure Boundary
Flexible Connection	Pressure Boundary
Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Area Coolers) Tubes	Leakage Boundary (Spatial)
Piping, piping components	Pressure Boundary
Silencer / Muffler	Pressure Boundary
Valve Body	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.3.2-21 Turbine Building HVAC System
Summary of Aging Management Evaluation**

2.3.4 STEAM AND POWER CONVERSION SYSTEM

The following systems are addressed in this section:

- Condensate and Condensate Transfer System (2.3.4.1)
- Condenser Air Removal and Off-Gas System (2.3.4.2)
- Feedwater/High Pressure Coolant Injection System (2.3.4.3)
- Main Generator and Auxiliary System (2.3.4.4)
- Main Steam System (2.3.4.5)
- Main Turbine and Auxiliary System (2.3.4.6)

2.3.4.1 **Condensate and Condensate Transfer System**

Description

The Condensate and Condensate Transfer (CTS) System condenses steam exhausted from the low-pressure turbines and the turbine bypass valves. This condensate then becomes the primary water supply to the Feedwater/High Pressure Coolant Injection System, and ultimately to the reactor, during operations and while the plant is in a shutdown condition. The CTS System consists of the following plant subsystems:

- Resin transfer and regeneration system
- Sulphuric acid transfer
- Condensate pump inlet, spray system and miscellaneous condenser piping
- Condensate pumps discharge to reactor feedwater booster pump inlet and to condensate storage tank
- Condensate storage and transfer
- Condensate transfer
- Condensate makeup to torus from condensate transfer system to blocking valve
- Condensate makeup to torus, torus to first blocking valve
- Condensate makeup to main condenser from storage surge tanks
- Caustic soda transfer
- Sealing water, condensate or filtered
- Seal water
- Low-pressure air
- Main turbine unknown subsystem

The CTS System consists of three 50 percent capacity condensate pumps, two full-size condensate transfer pumps, six mixed-bed condensate demineralizers, one main condenser, four condensate iron prefilters, two iron prefilter backwash receiving tanks, one condensate spray pump, and two condensate storage tanks (CSTs). It includes all connected instrumentation, piping, valves, and associated equipment.

The main condenser is divided into three sections: low-pressure, intermediate-pressure, and high-pressure, to improve turbine efficiency. Cooling water is applied to all three sections by the Circulating Water System, which transfers the heat to Lake Ontario as its ultimate heat sink. The main condenser supports Reactor Protection System instrumentation that detects the loss of vacuum to initiate a turbine stop valve closure (at 20 inches of vacuum) and a main steam line isolation (at 7 inches of vacuum), each of which eventually leads to a reactor scram. The main condenser also acts as a collecting basin for various leak-offs, drains and relief valve discharges from balance of plant systems.

Under emergency conditions, such as a small break loss of coolant accident (LOCA) where primary coolant loss is in excess of the capacity of the control rod drive pumps, but where the reactor vessel does not depressurize rapidly enough to allow the Core Spray System to inject, the CTS System supplies water from the two CSTs utilizing the main condenser hotwell. This function supports the high pressure coolant injection (HPCI) mode of operation to supply makeup water to the reactor, and utilizes the two condensate pumps, as well as the condensate prefilters and demineralizers.

Another function of the CTS System is to remove impurities from the condensed liquid for re-use as high-grade water. It does this via iron prefilters and demineralizers that filter the condensate by mechanical filtration and ion exchange.

The two full-size horizontal centrifugal condensate transfer pumps (one running and one in standby) take suction from the condensate surge and storage tanks. These pumps supply demineralized water to various systems and components throughout the plant.

Intended Functions

1. Provide primary containment boundary. The Condensate and Condensate Transfer System includes lines which penetrate the containment. 10 CFR 54.4.(a)(1)
2. Provide emergency core cooling where the equipment provides coolant directly to the core. The Condensate and Condensate Transfer System provides makeup coolant inventory to the emergency condensers of the Emergency Cooling (EC) System, which provides for decay heat removal in the event reactor feedwater is lost and the main condenser is unavailable, via the CST. 10 CFR 54.4(a)(1)
3. Ensure adequate cooling in the spent fuel pool to maintain stored fuel within acceptable temperature limits. The Condensate and Condensate Transfer System maintains spent fuel pool level in support of providing adequate cooling to the spent fuel pool. 10 CFR54.4(a)(1)
4. Provide heat removal from safety-related heat exchangers. The Condensate and Condensate Transfer System contains condensate pump heat exchangers that maintain pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR54.4(a)(1)
5. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Condensate and Condensate Transfer System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor and turbine buildings. 10 CFR 54.4(a)(2)
6. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Includes nonsafety-related SSCs that are functionally relied upon to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or (b) directly mitigate the consequences of a design basis event (DBE). The Condensate and Condensate Transfer System in conjunction with the Feedwater/High Pressure Coolant Injection System provides coolant to the reactor during small-break LOCA events when the reactor has not depressurized. 10 CFR 54.4(a)(2)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient without Scram (10 CFR 50.62). Condensate and Condensate Transfer System is part of the HPCI function and acts as a source of water for HPCI per the main condenser and the CSTs. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that

demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Condensate and Condensate Transfer System has environmentally qualified components. 10 CFR 54.4(a)(3)

9. Relied upon 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). The Condensate and Condensate Transfer System supports the primary method by providing makeup to the reactor utilizing the Control Rod Drive System taking suction from the condensate storage tanks. The system also supports the secondary method for process monitoring of torus level indication using Condensate and Condensate Transfer System components. 10 CFR 54.4(a)(3)
10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Condensate and Condensate Transfer System supports SBO recovery by providing inventory for reactor vessel makeup by the Feedwater/HPCI system as well as by providing makeup to the isolation condenser when the alternate AC power source becomes available to power condensate transfer pumps. The Condensate and Condensate Transfer System also includes a torus level monitoring function via level instrumentation. 10 CFR 54.4(a)(3)

UFSAR References

V.E.1.0
VII.A.2.1
VII.I.2.0
VIII.A.1.1
VIII.A.2.1
XI.B.1.0
XI.B.2.0
XI.B.5.0
XI.B.6.0
XI.B.6.0A
XI.B.7.0

License Renewal Boundary Drawings

SLR-NMP1-B18042C-002
SLR-NMP1-C18003C-001
SLR-NMP1-C18003C-002
SLR-NMP1-C18003C-004
SLR-NMP1-C18004C
SLR-NMP1-C18005C-002
SLR-NMP1-C18006C-002
SLR-NMP1-C18007C-001
SLR-NMP1-C18008C
SLR-NMP1-C18009C-001
SLR-NMP1-C18009C-002
SLR-NMP1-C18010C-001
SLR-NMP1-C18010C-002
SLR-NMP1-C18010C-005

SLR-NMP1-C18022C-001
SLR-NMP1-C18022C-002
SLR-NMP1-C18029C
SLR-NMP1-C18032C
SLR-NMP1-C18033C-001
SLR-NMP1-C18034C-001
SLR-NMP1-C18034C-002
SLR-NMP1-C18034C-003
SLR-NMP1-C18035C
SLR-NMP1-C18036C
SLR-NMP1-C18041C-001
SLR-NMP1-C18041C-004
SLR-NMP1-C18041C-007
SLR-NMP1-C18041C-012
SLR-NMP1-C18045C-007
SLR-NMP1-C18048C

**Table 2.3.4-1 Condensate and Condensate Transfer System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Expansion Joints	Pressure Boundary
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Condensate Pump Coolers) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Main Condenser Hotwell) Shell Side Components	Pressure Boundary
Hoses	Leakage Boundary (Spatial)
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Condensate Pumps)	Pressure Boundary
Pump Casing (Condensate Transfer Pumps)	Pressure Boundary
Strainer (Element)	Filter
Tanks (Condensate Demineralizers)	Pressure Boundary
Tanks (Condensate Prefilters)	Pressure Boundary
Tanks (Condensate Surge & Storage Tank)	Pressure Boundary
Tanks (Head Tank)	Leakage Boundary (Spatial)
Tanks (Resin Add Tank)	Leakage Boundary (Spatial)
Tanks (Resin Heater Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.4.2-1 Condensate and Condensate Transfer System
Summary of Aging Management Evaluation**

2.3.4.2 **Condenser Air Removal and Off-Gas System**

Description

The Condenser Air Removal and Off-Gas (CAR) System is a normally operating system that removes the accumulated non-condensable radioactive gases in the main condenser during plant startup and normal operation. The CAR System consists of the following plant systems:

- Steam supply to air ejector, mixing jet and offgas preheater (between reducing valve and equipment)
- Steam supply to mixing jet and offgas preheater after pressure reducing valve
- Steam jet air ejector – steam supply system
- Main condenser air removal
- Condenser offgas (from jet air ejector)
- Condenser offgas, recombiner inlet to recombiner condenser inlet
- Condenser offgas, recombiner condenser outlet to existing connection as chimney
- Condenser offgas, inlet to the vacuum pumps, to the outlet of the offgas moisture separator
- Condenser offgas, mixing jet inlet to recombiner inlet
- Condenser offgas, chiller to deicing water buffer tank outlet
- Turbine gland seal exhaust
- Freon refrigeration system for offgas chillers

Non-condensable gases are removed by two-stage steam jet air ejectors that draw the gas volume from the main condenser and are then directed to the off-gas recombiner system for processing. The offgas recombiner system recombines oxygen and hydrogen, condenses the water vapor, and holds up these gases to minimize radioactive releases to the environment. The system exhausts the gases to the main stack and all water condensed is returned to the main condenser. The gases evacuated by this system are mainly concentrated in the condenser, but steam, air, and other gases evacuated by the steam packing exhausters are also discharged to the CAR System. The CAR System contains heat exchanger components that provide a flow path for the Condensate and Condensate Transfer System that preserves the (a)(2) functional intended function for that system

This system also includes equipment to draw the initial vacuum on the main condenser during plant startup. This equipment includes two off-gas vacuum pumps, two vacuum pump coolers and two off-gas moisture separators.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Condenser Air Removal and Off-Gas System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. 10 CFR 54.4(a)(2)
2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Includes nonsafety-related SSCs that are functionally

relied upon to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or (b) directly mitigate the consequences of a design basis event (DBE). The Condenser Air Removal and Off-Gas System heat exchangers maintain pressure boundary for the Condensate and Condensate Transfer System that has an a(2) functional intended function to provide emergency core cooling by supplying coolant to the Feedwater/HPCI System. 10 CFR 54.4(a)(2)

UFSAR References

VII.I.2.0

XI.B.3.0

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001

SLR-NMP1-C18003C-001

SLR-NMP1-C18003C-004

SLR-NMP1-C18010C-001

SLR-NMP1-C18010C-002

**Table 2.3.4-2 Condenser Air Removal and Off-Gas System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (Offgas SJAE Inter and After Condenser) Tube Sheet	Pressure Boundary
Heat Exchanger – (Offgas SJAE Inter and After Condenser) Tube Side Components	Pressure Boundary
Heat Exchanger – (Offgas SJAE Inter and After Condenser) Tubes	Pressure Boundary
Heat Exchanger – (Recombiner Condenser) Tube Sheet	Pressure Boundary
Heat Exchanger – (Recombiner Condenser) Tube Side Components	Pressure Boundary
Heat Exchanger – (Recombiner Condenser) Tubes	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.4.2-2 Condenser Air Removal and Off-Gas System
Summary of Aging Management Evaluation**

2.3.4.3 **Feedwater/High Pressure Coolant Injection System**

Description

The Feedwater/High Pressure Coolant Injection (FW/HPCI) System is the main source of processed water to the reactor during normal operations and while the plant is in a shutdown condition. The primary function of the FW/HPCI System is to transfer water from the two condensate storage tanks and the main condenser hotwell, that are evaluated in the Condensate and Condensate Transfer System, to the reactor pressure vessel (RPV) in order to maintain proper water level in the RPV. The FW/HPCI System also preheats the feedwater prior to entering the RPV. Although not a safety-related system, the FW/HPCI System is also designed to provide a highly reliable source of water to ensure that the core is adequately cooled under small break loss of coolant accident (LOCA) conditions, which do not result in a rapid depressurization of the (RPV).

The FW/HPCI System consists of the following plant systems:

- Feedwater heater drains
- High-pressure reactor feedwater (from reactor feedwater pumps to fifth extraction feedwater heater stop valve)
- Feedwater recirculation blocking valves to condenser
- High-pressure reactor feedwater (from fifth feedwater heater to external isolation valve)
- High-pressure feedwater bypass to condenser
- Reactor feedwater booster pump discharge to feedwater pumps inlet
- Reactor feedwater booster pump discharge for moisture separator cooling
- High-pressure hydro pump discharge
- Feedwater heater and line vents to condenser
- Feedwater heater safety valve discharge

The feedwater system consists of three feedwater booster pumps, three parallel strings of feedwater heaters (consisting of four low-pressure feedwater heaters and one high-pressure feedwater heater each), three feedwater pumps with associated flow control valves, two injection paths to the RPV in which each path contains isolation valves, two reactor nozzles, and two feedwater spargers located within the RPV. The feedwater booster pumps take suction from piping on the discharge of the three condensate pumps which take suction from the main condenser hotwell; minimum flow lines are connected to the discharge of each booster pump to provide pump protection. The booster pumps supply suction to the reactor feedwater pumps (RFPs) through three parallel strings of feedwater heaters. There are three horizontal centrifugal RFPs with one pump driven from the shaft of the high-pressure turbine, and the other two pumps electrically-driven by motors. A separate drain cooler is provided for each of the lowest pressure heaters, while the other feedwater heaters have integral drain coolers. Extraction steam from the main turbine is used to provide heat to the feedwater heaters.

The feedwater system includes a passive zinc injection system, designed and installed to inject zinc ions into the reactor water via the feedwater line. The zinc injection system is installed to reduce Cobalt-60 buildup in the primary piping corrosion films.

The high pressure coolant injection (HPCI) system is an operating mode of the FW/HPCI

System. The purpose of the HPCI system with one of the two emergency cooling systems and two core spray systems is to provide adequate cooling of the reactor core under abnormal and accident conditions, remove the heat from radioactive decay and residual heat from the reactor core at such a rate that fuel clad melting would be prevented, and provide for continuity of core cooling over the complete range of postulated break sizes in the primary system process barrier. The HPCI mode of feedwater operation will normally operate in the event of a small reactor coolant line break which exceeds the capability of the control rod drive (CRD) pumps, but not large enough to allow the core spray system to be effective. High pressure coolant injection is not an engineered safeguards system and is not considered in any LOCA analyses. The HPCI mode of feedwater operation is auto-initiated by low reactor vessel water level and high drywell pressure, causing reactor scram and turbine trip. A sustained high reactor water level reactor protection system (RPS) signal coincident with an open feedwater control valve will selectively trip the associated feedwater pump. The clutch of the shaft-driven pump will also be disengaged immediately upon high reactor water level.

The HPCI System utilizes the following components to fulfill its functions: the two condensate surge and storage tanks, the main condenser hotwell, two condensate pumps, condensate filters, condensate demineralizers, two feedwater booster pumps, feedwater heaters, two motor-driven feedwater pumps, an integrated control system, and associated piping and valves.

The Class 1 portion of the FW/HPCI System includes containment isolation valves and piping. These SSCs are included in the Reactor Coolant Pressure Boundary System. The feedwater nozzles and safe ends are included in the RPV System and the feedwater spargers and thermal shields are included in the Reactor Vessels Internals System.

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The Feedwater/High Pressure Coolant Injection System heat exchangers and associated valves maintain pressure boundary of the Reactor Building Closed Loop Cooling System as it supports heat removal for safety-related heat exchangers. 10 CFR 54.4(a)(1)
2. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Feedwater/High Pressure Coolant Injection System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor and turbine buildings. 10 CFR 54.4(a)(2)
3. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Includes nonsafety-related SSCs that are functionally relied upon to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function, or (b) directly mitigate the consequences of a Design Basis Event (DBE). The Feedwater/High Pressure Coolant Injection System provides coolant from the Condensate and Condensate Transfer System to the reactor during small-break LOCA events when the reactor has not depressurized. 10 CFR 54.4(a)(2)
4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated

Transient Without Scram (10 CFR 50.62). The Feedwater/High Pressure Coolant Injection System is an injection system credited for RPV level control during an ATWS. 10 CFR 54.4(a)(3)

5. Relied upon 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). The Feedwater/High Pressure Coolant Injection System includes components that support the various analyses related to the NFPA 805 transition, including High-Safety-Significant Fire PRA, Safe Shutdown (SSD), and Non-Power Operation (NPO). 10 CFR 54.4(a)(3)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Feedwater/High Pressure Coolant Injection System supports SBO coping by providing the path for the diesel driven fire pump to the reactor vessel. The Feedwater/High Pressure Coolant Injection System also supports SBO recovery by automatically initiating reactor vessel makeup using the FW/HPCI pumps following restoration of AC power. 10 CFR 54.4(a)(3)

UFSAR References

VII.I
VIII.B.2.4
XI.A..1
XI.B.8.0
XI.B.9.0
XI.B.10.0

License Renewal Boundary Drawings

SLR-NMP1-C18002C-002
SLR-NMP1-C18002C-003
SLR-NMP1-C18003C-004
SLR-NMP1-C18004C
SLR-NMP1-C18005C-001
SLR-NMP1-C18005C-002
SLR-NMP1-C18005C-004
SLR-NMP1-C18006C-001
SLR-NMP1-C18022C-002
SLR-NMP1-C18022C-003
SLR-NMP1-C18024C
SLR-NMP1-C18041C-001

**Table 2.3.4-3 Feedwater/High Pressure Coolant Injection System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Drip Pan	Leakage Boundary (Spatial)
Flow Device	Pressure Boundary
	Throttle
Heat Exchanger – (Feedwater Heaters No. 5) Tubes	Pressure Boundary
Heat Exchanger – (Actuator Package Cooling Skid Heat Exchanger Tubing) Tubes	Leakage Boundary (Spatial)
Heat Exchanger – (Drain Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Drain Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Drain Cooler) Tubes	Pressure Boundary
Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Side Components	Pressure Boundary
Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tubes	Pressure Boundary
Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Sheet	Pressure Boundary
Heat Exchanger – (Feedwater Heaters No. 5) Tube Side Components	Pressure Boundary
Heat Exchanger – (Feedwater Heaters No. 5) Tubes	Pressure Boundary
Heat Exchanger – (Feedwater Heaters No. 5) Tube Sheet	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tubes	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Pump Jacket Water Cooling) Shell Side Components	Heat Transfer
	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Shell Side Components	Pressure Boundary

Component Type	Intended Function
Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger – (Reactor Feedwater Pump Oil Coolers) Tubes	Heat Transfer
	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Pump Casing (Auxiliary Oil Pump for Motor-Driven RFW Pumps)	Pressure Boundary
Pump Casing (Feedwater Booster Pumps)	Pressure Boundary
Pump Casing (Feedwater Pumps)	Pressure Boundary
Pump Casing (Feedwater Seal Injection Booster Pumps)	Pressure Boundary
Pump Casing (Hydrostatic Test Pump)	Leakage Boundary (Spatial)
Pump Casing (Turbine-Driven RFW Pump Clutch Hydraulic Actuator Pump)	Leakage Boundary (Spatial)
Strainer (Element)	Filter
Tanks (Dissolution Column)	Leakage Boundary (Spatial)
Tanks (Motor-Driven RFW Pump Oil Reservoir)	Pressure Boundary
Tanks (Turbine-Driven RFW Pump Clutch Oil Reservoir)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System
Summary of Aging Management Evaluation

2.3.4.4 **Main Generator and Auxiliary System**

Description

The Main Generator and Auxiliary (MGA) System provides an electrical pathway for the main generator output to the transmission system. The MGA System mechanically maintains leakage boundary integrity to preclude system interactions. The MGA System is in scope of subsequent license renewal. However, portions of the MGA System are not required to perform intended functions and are not in scope. The MGA System contains the following plant systems:

- High-pressure instruments
- Main generator miscellaneous
- 24 kV generator leads
- 500 VDC electrical system
- Stator winding cooling water
- Hydrogen seal oil system
- Hydrogen (H₂) truck fill and pressure control station (H₂ control panel for main generator cooling)
- Hydrogen (H₂) supply for generator
- Hydrogen (H₂) vent and drain
- Seal oil

The MGA System maintains leakage boundary integrity to preclude system interactions. For this reason, this system's pressure retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid and steam filled portions of the system located within the turbine building. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system.

The MGA System provides a current path for the Unit 1 main generator output over two 345KV transmission lines to the transmission system. This current path is not part of the SBO recovery current path. However, the MGA System is credited by NFPA 805 for Non-Power Operations when the plant is configured to back feed the 4160 V power boards through the station service transformer. The back feed configuration provides an additional source of offsite power, is credited for fire protection during non-power operations and is in scope for subsequent license renewal.

The in-scope portion of the MGA System is comprised of buses, cabinets, indicators, protective relays, transformers, indicators switches, circuit breakers, fuses, fuse holders, cables, and cable connections.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Main Generator and Auxiliary System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs in the turbine building. 10 CFR 54.4(a)(2)

2. Relied upon 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). The Main Generator and Auxiliary System is relied upon for Non-Power Operations (NPO) event via the supply of offsite power. 10 CFR 54.4(a)(3)

UFSAR References

XI.B.1.0

License Renewal Boundary Drawings

SLR-NMP1-C18022C-003

SLR-NMP1-F45836C-001

SLR-NMP1-F45836C-002

**Table 2.3.4-4 Main Generator and Auxiliary System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Shell Side Components	Leakage Boundary (Spatial)
Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)
Piping elements	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump Casing (Stator Winding Cooling Water Pumps)	Leakage Boundary (Spatial)
Tanks (Cal Gas Humidifier)	Leakage Boundary (Spatial)
Tanks (Stator Water Cooling Demineralizer)	Leakage Boundary (Spatial)
Tanks (Stator Water Cooling Storage Tank)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)

The aging management review results for these components are provided in:

**Table 3.4.2-4 Main Generator and Auxiliary System
Summary of Aging Management Evaluation**

2.3.4.5 **Main Steam System**

Description

The Main Steam (MS) System supplies high-pressure steam produced by the reactor via steam lines through the steam line tunnel to the turbine building to be directed to either the main turbine during normal plant operation or bypassed directly to the main condenser. The MS System consists of the following plant subsystems:

- Main steam, reactor outlet to external isolation valve outlet
- Main steam, external isolation valve outlet to turbine inlet
- Main steam, turbine bypass to condenser
- High-pressure steam supply to seal regulator
- Main steam line power operated relief valve discharge

The MS System consists of two main steam lines that start at the discharge of the two outboard main steam isolation valves (MSIVs) and ends at the inlets to the turbine stop, control, and bypass valve manifolds and at the inlet of various components that utilize main steam. It includes all connected instrumentation, piping, valves, and associated equipment. The system also includes the discharge lines of the six electromatic relief valves (ERVs) that terminate in the torus. All safety-related instrumentation associated with main steam, regardless of where it transitions to the Main Turbine and Auxiliary System, are addressed in the MS System scoping report (i.e., turbine first stage pressure instrumentation).

MS System piping from the reactor pressure vessel up to and including the outboard MSIVs on each of the two main steam lines as well as the ERVs is included in the scope of the Reactor Coolant Pressure Boundary (RCPB) System. The RCPB license renewal system contains all ASME Class I piping, piping components and valves outboard of the reactor vessel nozzles including those components from the MS System. ERV discharge piping, which is ASME Class II, is part of the MS System.

Piping, piping components, and valves downstream of the MSL inlets to the main turbine stop, control, and bypass valve manifolds, including the high- and low-pressure turbines, the various reheater drain and vents systems, and the steam seal regulator are all included in the scope of the Main Turbine and Auxiliaries (MTA) System.

Intended Functions

1. Provide emergency heat removal from primary containment and provide containment pressure control. The Main Steam System contains the ERV discharge piping and vacuum breakers which prevents backflow and leakage between the drywell and torus and provides a flow path for released steam to the torus to minimize pressure and thermal effects on the primary containment during plant events. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Main Steam System contains differential pressure transmitters connected to each main steam line to sense flow rates that provide inputs to the Reactor Protection System (RPS) to initiate trip signal on indication of flow rates above established limits. 10 CFR 54.4(a)(1)

3. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Main Steam System contains first-stage pressure switches connected to the high-pressure turbine that provide a bypass of the turbine stop and control valve closure RPS contacts during startup. 10 CFR 54.4(a)(1)
4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Main Steam System includes nonsafety-related components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs located in the reactor and turbine buildings. 10 CFR 54.4(a)(2)
5. Relied upon 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). The Main Steam System supports the secondary method for pressure control for fire safe shutdown. 10 CFR 54.4(a)(3)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Main Steam System includes systems that contain environmentally qualified components. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Main Steam System provides overpressure protection by directing steam through the ERV discharge piping to the suppression pool during an ATWS. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Main Steam System supports SBO coping by providing discharge piping pressure boundary downstream of power operated relief valves. 10 CFR 54.4(a)(3)

UFSAR References

V.A.2.0
V.B.1
V.B.5
VII.A.2.0
VIII.C.2.1.1
XI.A.3
XI.B.1
XI.B.1.0

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001
SLR-NMP1-C18006C-001
SLR-NMP1-C18041C-001

**Table 2.3.4-5 Main Steam System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Expansion Joints	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial)
	Pressure Boundary
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.4.2-5 Main Steam System
Summary of Aging Management Evaluation**

2.3.4.6 **Main Turbine and Auxiliary System**

Description

The Main Turbine and Auxiliary (MTA) System contains the following plant systems:

- External isolation valve outlet to turbine inlet
- Turbine bypass to condenser
- High-pressure steam supply to second reheater
- Second stage reheater drains and vents
- Hot reheat steam to low-pressure turbine from moisture separator outlet to low-pressure turbine
- Cold reheat steam to reheater from high-pressure turbine to moisture separator
- Extraction steam to first reheater
- Extraction steam to fifth feedwater heater
- Extraction steam to fourth feedwater heater
- Extraction steam to third feedwater heater
- Extraction steam to second feedwater heater
- Extraction steam to first feedwater heater
- Turbine steam seal regulator, low-pressure system
- Leak off from steam seal regulator to first extraction line and relief valve, discharge line to condenser
- Gland seal exhaust from turbine to gland seal condenser
- Miscellaneous steam drains
- Moisture separator drains and vents (to fourth heater and condenser)
- First stage reheater drains and vents
- Turbine oil storage and purification
- Turbine oil vents
- Reheater dryer system blower to building ventilation system
- Turbine-generator control system
- Turbine protection system
- Turbine supervisory instruments

With the exception of the turbine bypass valves, the intended function of the MTA System for license renewal is to maintain leakage boundary integrity to preclude system interactions. For this reason, this system's pressure retaining components located in areas where there are potential spatial interactions with safety-related equipment have been included in the scope of license renewal. This includes the liquid and steam filled portions of the system located within specific areas of the turbine building. Included in this boundary are pressure-retaining components relied upon to preserve the leakage boundary intended function of this system.

The MTA System includes the turbine bypass valves that are credited for support of fire protection as they perform an (a)(3) Fire Protection function.

Intended Functions

1. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Main Turbine and Auxiliary System contains nonsafety-related, liquid and steam filled lines in the Turbine Building which have the

potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)

2. Relied upon 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). The turbine bypass valves are credited to maintain reactor pressure for Fire Protection. 10 CFR 54.4(a)(3)

UFSAR References

VIII.B.2.3

XI.B.1.0

License Renewal Boundary Drawings

SLR-NMP1-C18002C-001

SLR-NMP1-C18002C-003

SLR-NMP1-C18022C-003

SLR-NMP1-C18025C

SLR-NMP1-C18037C

**Table 2.3.4-6 Main Turbine and Auxiliary System
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Closure)	Mechanical Closure
Piping, piping components	Leakage Boundary (Spatial)
Tanks (Lube Oil Storage Tank)	Leakage Boundary (Spatial)
Tanks (Waste Oil Receiver)	Leakage Boundary (Spatial)
Valve Body	Leakage Boundary (Spatial)
	Pressure Boundary

The aging management review results for these components are provided in:

**Table 3.4.2-6 Main Turbine and Auxiliary System
Summary of Aging Management Evaluation**

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES AND COMPONENT SUPPORTS

The following structural components are addressed in this section:

- Component Supports Commodity (2.4.1)
- Primary Containment (2.4.2)
- Reactor Building (2.4.3)
- Screen and Pump House Building (2.4.4)
- Structural Commodity Group (2.4.5)
- Turbine, Waste Handling, and Admin. Structures (2.4.6)
- Yard Structures (2.4.7)

2.4.1 **Component Supports Commodity**

Description

The Component Supports Commodity consists of component supports that provide connections between a system component and a structural member such as a concrete wall or floor or structural steel beam or column. Supports include seismic anchors or restraints, support frames, spring hangers, rod hangers, guides, stops, straps, bolting, and clamps. Specialty components include snubbers and sliding surfaces. The Component Supports Commodity includes:

- Supports for ASME Class 1, 2, and 3 piping and components.
- Supports for ASME Class MC components including clevis pins, suppression chamber seismic restraints, suppression chamber support saddles and columns, and vent system supports
- Supports for raceways, cable trays, conduit, HVAC ducts, tube track, and instrument tubing
- Supports for racks, panels, cabinets and enclosures for electrical equipment and instrumentation
- Supports for non-ASME piping for emergency diesel generator, HVAC system components, piping and supports, and miscellaneous mechanical equipment
- Supports for platforms, supports for high-energy line break shielding, masonry walls, and other miscellaneous structures

The purpose of a support is to transfer loads such as gravity, thermal, seismic, and other lateral and vertical loads imposed on or by the SSCs to the supporting building structural element or foundation. Sliding surfaces, when incorporated into the support design, permit release of lateral forces but are relied upon to provide vertical support. Specialty supports such as snubbers only resist seismic forces. Other support types, such as guides and stops, allow displacement in a specified direction or preclude unanalyzed movements and interactions.

The Component Supports Commodity also includes supports for SSCs, which are not within the scope of license renewal, but their supports are required to restrain or prevent physical interaction with safety-related systems and components (e.g., Seismic II components mounted over or around Seismic I equipment) and nonsafety-related component supports that are supported by a safety-related structure. The supports include, but are not limited to, support members, welded and bolted connections, sliding surfaces, concrete anchors, concrete embedments, and grout.

Included in the evaluation boundary of the Component Supports Commodity for the components indicated above are constant and variable load spring hangers, rod hangers, clamps, straps, guides, stops, seismic anchors or restraints, support frames, support members, sliding surfaces, welds, bolted connections, and support anchorage to building structures. Snubbers are also included in the boundary of this commodity group; however, they are considered active components and are not subject to aging management review except for the end connections, which perform a passive function for structural support. The stabilizer supports from the

reactor pressure vessel to the reactor shield wall are addressed in the Component Supports Commodity.

Component Supports are treated as a commodity group because of similarities in design, materials, aging effects, and environments within the various station structures.

Component Supports that are in scope for license renewal are located in structures and areas with mechanical or electrical components which are also in scope. Component Supports are not in scope for license renewal when installed in structures or areas where there are no mechanical or electrical components in scope.

Not included in the evaluation boundary of the Component Supports are concrete equipment foundations, high-energy line break shielding, concrete embedments, and concrete anchors used for components other than supports listed herein. Supporting members internal to components are included within the scope of those mechanical or electrical systems. Structural foundations for buildings are included within the scope of the individual structures. These commodities are evaluated separately with the license renewal structure that contains them. The spent fuel storage racks are evaluated with the Spent Fuel Pool Cooling and Storage System. Conduit, cable trays, cabinets, enclosures, and panels for electrical equipment and instrumentation are evaluated in the Structural Commodity Group. Structural commodities, including their associated structural bolting and concrete anchors, are evaluated with the Structural Commodity Group. The Structural Commodity Group evaluates electrical enclosures and raceways (including cable trays and tube track); hazard barriers and elastomers; insulation; and structural miscellaneous components (e.g., high energy line break shields, metal platforms, grating, stairs, and ladders). The Primary Containment evaluates the reactor shield wall and the stabilizer supports from the reactor shield wall to the drywell.

Component Supports within the scope of license renewal are not shown on the license renewal boundary drawing since these commodities are included within structures in scope for license renewal.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)
2. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
3. Provides a safe means for handling safety-related components and loads above or near safety-related components. 10 CFR 54.4(a)(2)
4. Provides physical support, shelter, and protection for systems, structures, and components relied upon 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). 10 CFR 54.4(a)(3)
5. Provides physical support, shelter, and protection for systems, structures, and

components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)

6. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)
7. Provides structural support or restraint to SSCs in the scope of license renewal. 10 CFR 54.4(a)(1), (a)(2), (a)(3)

UFSAR References

XV.C.2.2.4
XVI.D.1.0
XVI.D.1.2
XVI.D.2.0

License Renewal Boundary Drawings

SLR-NMP1-S-1

**Table 2.4-1 Component Supports Commodity
Components Subject to Aging Management Review**

Component Type	Intended Function
Supports for ASME Class 1 piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support
Supports for ASME Class 1 piping and components: sliding surfaces	Structural Support
Supports for ASME Class 1 piping and components: stabilizers (reactor vessel to reactor shield wall)	Structural Support
Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for ASME Class 2 and 3 piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support
Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support
Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for ASME Class MC piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for ASME Class MC piping and components: constant and variable load spring hangers; guides; stops	Structural Support
Supports for ASME Class MC piping and components: sliding surfaces	Structural Support

Component Type	Intended Function
Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: sliding support bearings; sliding support surfaces	Structural Support
Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support
Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support

Component Type	Intended Function
Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support
Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support

The aging management review results for these components are provided in:

Table 3.5.2-1 Component Supports Commodity
Summary of Aging Management Evaluation

2.4.2 **Primary Containment**

Description

The Nine Mile Point Nuclear Station, Unit 1 primary containment structure is a Class I structure. The primary containment is a Mark I design that consists of a drywell, a suppression chamber in the shape of a torus, and a connecting vent system between the drywell and the suppression chamber. It also includes the structural portions of primary containment penetrations and associated internal structures. The primary containment structure is entirely within the reinforced concrete portion of the Reactor Building. The drywell is enclosed by a concrete biological shield that is considered part of the Reactor Building.

Drywell:

The drywell is a steel pressure vessel with a spherical lower portion, a cylindrical upper portion, and a removeable steel head. The drywell houses the reactor pressure vessel (RPV) as well as the reactor recirculation loops and their branch connections. Closure for the top portion of the drywell vessel (the drywell head) is bolted and double sealed by two o-ring gaskets. The drywell head is removed during refueling operations. A flexible bellows seal connects the reactor head cavity liner (part of the Reactor Building) to the drywell shell. A horizontal steel refueling seal platform inside the drywell shell is connected to the RPV flange by a second flexible bellows seal. The bellows seals, in conjunction with the refueling seal platform, platform covers, and associated bolting, provide a watertight barrier during refueling to permit flooding above the RPV flange while preventing water from entering the drywell.

In addition to the drywell head, two double-door air locks and one bolted equipment hatch are provided for access to the drywell. Locking mechanisms on each air lock door maintain a tight seal when the locks are subjected to internal pressure. The doors are mechanically interlocked; neither door may be operated unless the other door is closed and locked. The bolted equipment hatch is double-sealed by two o-ring gaskets.

Four basic types of penetrations through the drywell shell are evaluated with the Primary Containment: electrical, hot fluid lines, cold fluid lines, and lines welded directly to the containment.

Reinforced concrete structures inside the drywell include the drywell floor, reactor pedestal, and the reactor shield wall surrounding the RPV. Inside the drywell, a portion of the lower spherical drywell shell is filled with concrete to form a floor above the bottom of the drywell and approximately level with the vent pipes to the torus. This floor provides a working base for supporting the reactor structures and components inside the drywell. The reactor pedestal is a reinforced concrete cylinder keyed into the drywell floor that provides structural support to the RPV and the annular reactor shield wall around the RPV. The inside surface of the reactor pedestal is lined with a carbon steel liner plate. The reactor shield wall attenuates neutrons and gamma flux to the drywell shell. The inside and outside surfaces of the reactor shield wall concrete are covered with steel plates.

The upper portion of the drywell is supported by a stabilizer system. Stabilizer

brackets below the RPV flange are connected to tension bars with flexible couplings; these bars are connected to the top of the reactor shield wall. The reactor shield wall, in turn, is anchored by rigid bars to the drywell shell. The drywell shell is anchored at the same elevation to the supporting concrete structure (i.e., the biological shield). This configuration serves to transmit the upper lateral drywell loads to the Reactor Building.

The base of the RPV support skirt is continuously supported by a ring girder and sole plate fastened to the top of the reactor pedestal, which is supported by the lower part of the drywell. The lower part of the drywell shell is held to the concrete foundation through the steel support skirt welded to the underside of the shell and anchored to the Reactor Building foundation concrete. Concrete is compactly filled in and around the support skirt by the preplaced aggregate method so that the skirt and the foundation act in unison to support drywell loads.

Internal structural steel at various elevations of the drywell provides structural support to safety-related and nonsafety-related systems and equipment. It also includes floor framing steel for the various platforms inside the drywell that provide personnel access to the equipment for maintenance and testing. Miscellaneous steel includes steel components such as grating, ladders, and handrails inside the drywell.

At the top of the foundation, a sandpocket was installed around the bottom of the drywell. Above this level, the drywell shell is separated from the concrete biological shield (part of the Reactor Building) by an air gap of at least two inches to accommodate thermal expansion.

Torus:

The torus is a steel pressure vessel below and encircling the drywell. The torus is made up of twenty mitered sections and is connected to the drywell by ten equally spaced vent pipes. The torus is supported by two external columns (one on the outer diameter, one on the inner diameter) and an intermediate saddle at each of the mitered sections. The columns are welded to the torus shell at the top and connected to the reinforced concrete foundation of the Reactor Building by a system of base plates, stiffeners, and anchor bolts. Three access manholes with double-gasketed bolted covers provide access from the Reactor Building to the torus. These access ports are bolted closed when primary containment integrity is required. The torus provides support for many other containment-related structures, such as the vent system.

Major components inside the torus include emergency core cooling system suction strainers (part of Core Spray and Containment Spray Systems), the suppression chamber (torus) spray header (part of the Containment Spray System), as well as the vent line header, downcomers, and Y-quenchers (discussed below).

The torus is penetrated at multiple locations by piping, instrument lines, and electrical raceways. The penetration configurations consist of sleeves welded to the torus. Penetrations required to accommodate thermal movements are provided with expansion bellows.

Structural steel inside the torus provides structural support to safety-related and

nonsafety-related systems and equipment. Miscellaneous steel includes steel components such as grating, ladders, and handrails inside the torus.

Vent System:

The drywell and torus are interconnected by a vent system. Ten large vent pipes connect the drywell to a vent ring header, which is located within the torus airspace. The pipes are enclosed with sleeves and are provided with expansion bellows to accommodate differential motion between the drywell and the torus. A dished and stiffened vent header deflector is provided at the drywell opening to each of the vent pipes leading to the torus to prevent possible damage to the vents from missiles or jet forces. Projecting downward from the vent ring header are 120 downcomer pipes, terminating about four feet below the surface of the torus water volume.

The vent system also provides support for safety-relief valve (SRV) discharge lines, which are routed inside the vent lines to the torus. When an SRV actuates, steam is released from the primary system through a y-quencher submerged in the torus at the end of the discharge line (part of the Main Steam System).

The Primary Containment is provided with vacuum relief (part of the Containment Systems) to limit the pressure differential between (a) the drywell and the torus airspace and (b) between the torus and the atmosphere in the Reactor Building. The vacuum relief system assures that the design pressure limits are not exceeded for the two steel pressure vessels (i.e., the drywell and torus).

Included within the evaluation boundary of the Primary Containment and determined to be within the scope of license renewal are internal reinforced concrete structures inside of the drywell (including the drywell floor, reactor pedestal, and the reactor shield wall); steel elements comprising the drywell (including the drywell head, refueling seal platform, platform covers, and associated bolting as well as the drywell-to-Reactor Building seal, RPV-to-drywell seal, the reactor shield wall to drywell stabilizer system, equipment hatch, and air locks), torus (including access manholes, seals, and gaskets), and vent system (including vent header deflectors and downcomers); protective coatings for inside surfaces; moisture barriers; mechanical and electrical penetration assemblies; and penetration sleeves (including expansion bellows).

Not included in the evaluation boundary of the Primary Containment are mechanical and electrical systems and components housed within the structure; fire barriers; and component supports. Mechanical components associated with the primary containment (e.g., vacuum relief valves, containment inerting subsystem, and drywell cooling subsystem) are evaluated with the Containment Systems. The SRV discharge lines and y-quenchers are evaluated with the Main Steam System. The RPV support skirt is evaluated with the Reactor Pressure Vessel. Other mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities. Fire protection components are evaluated separately within the Fire Detection and Protection System. Foundation concrete supporting the drywell bottom, the biological shield surrounding the drywell, and shield plugs at the top of the reactor head cavity are evaluated with the Reactor Building. Support structures for the torus and the vent system, including their

respective bolting, are evaluated with Component Supports Commodity. The stabilizer supports from the reactor pressure vessel to the reactor shield wall are evaluated with Component Supports Commodity. Structural commodities, including their associated structural bolting and concrete anchors, are evaluated with the Structural Commodity Group. The Structural Commodity Group evaluates electrical enclosures and raceways (including cable trays and tube track); hazard barriers and elastomers; insulation; and structural miscellaneous components (e.g., metal platforms, grating, stairs, and ladders).

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)
2. Controls the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)
3. Controls the release of fission products to the secondary containment in the event of a design basis loss of coolant accident (LOCA) so that offsite consequences are within acceptable limits. 10 CFR 54.4(a)(1)
4. Provides sufficient air and water volumes to absorb the energy released to the containment in the event of design basis events so that the pressure is within acceptable limits. 10 CFR 54.4(a)(1)
5. Provides a source of water for emergency core cooling systems. 10 CFR 54.4(a)(1)
6. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
7. Provides physical support, shelter, and protection for systems, structures, and components relied upon 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). 10 CFR 54.4(a)(3)
8. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)
9. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
10. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

V.B
VI.A
VI.B
VI.C
VII.A
VII.B
X.J
XII.B
XV.C
XVI.B
XVI.D

License Renewal Boundary Drawings

SLR-NMP1-S-1

**Table 2.4-2 Primary Containment
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support
Bolting (Structural)	Structural Support
Concrete Elements: Anchors	Structural Support
Concrete Elements: Embedments	Structural Support
Concrete: All (accessible areas)	Direct Flow, HELB/MELB Shielding, Shielding, Structural Support
Concrete: All (inaccessible areas)	Direct Flow, HELB/MELB Shielding, Shielding, Structural Support
Concrete: Interior (accessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support
Concrete: Interior (inaccessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support
Concrete: near reactor vessel (reactor shield wall)	Direct Flow, HELB/MELB Shielding, Shielding, Structural Support
Equipment supports and foundations	Structural Support
Moisture barriers (caulking, flashing and other sealants)	Shelter/Protection, Water Retaining Boundary
Penetration - Containment - spares, access manholes, inspection ports	Shelter/Protection, Structural Pressure Barrier, Structural Support
Penetration - Containment Electrical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support
Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support
Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation
	Shelter/Protection, Structural Pressure Barrier, Structural Support
Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary
Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support
Personnel airlock, drywell emergency airlock, equipment hatch	Shelter/Protection, Structural Pressure Barrier, Structural Support
Personnel airlock, drywell emergency airlock: locks, hinges, and closure mechanisms	Structural Pressure Barrier, Structural Support

Component Type	Intended Function
Pipe Whip Restraints and Jet Impingement Shields	Direct Flow, HELB/MELB Shielding, Structural Support
Seals and gaskets	Shelter/Protection
Service Level I Coatings	Maintain Adhesion
Sliding Surfaces (drywell radial beam seats)	Structural Support
Steel Components: Ring Girder for the Reactor Vessel Support Skirt	Structural Support
Steel Components: Stabilizers (truss arrangements between reactor shield wall to drywell)	Structural Support
Steel Components: structural steel	Structural Support
Steel Components: structural steel (refueling seal platform)	Structural Support, Water Retaining Boundary
Steel Elements: liner, liner anchors, integral attachments (reactor pedestal and reactor shield wall)	Direct Flow, Structural Support
Steel elements: Downcomers	Direct Flow, Structural Support
Steel elements: Drywell - shell, head, embedded and sandpocket regions (accessible areas)	HELB/MELB Shielding, Missile Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support
Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support
Steel elements: Drywell - support skirt (inaccessible areas)	Structural Support
Steel elements: Refueling Bellows assemblies	Expansion/Separation, Water Retaining Boundary
Steel elements: Torus shell, ring girders	Structural Pressure Barrier, Structural Support, Water Retaining Boundary
Steel elements: Vent line, header, deflector, bellows	Direct Flow, Expansion/Separation, Structural Pressure Barrier, Structural Support
	Expansion/Separation, Structural Pressure Barrier
Structural Miscellaneous (refueling seal platform covers)	Water Retaining Boundary

The aging management review results for these components are provided in:

Table 3.5.2-2 Primary Containment
Summary of Aging Management Evaluation

2.4.3 **Reactor Building**

Description

The Reactor Building is a multi-story rectangular Class 1 structure, completely enclosing the primary containment structure. The building provides secondary containment when primary containment is in service, and primary containment during refueling, maintenance, or testing, when the primary containment structure is open or not required. The Reactor Building consists of the cask drop protection system, fresh fuel storage vault, reactor cavity, reactor internals storage pit, spent fuel storage pool, and transfer canal. The building houses the refueling and reactor servicing equipment, fresh and spent fuel storage facilities, emergency cooling system, reactor cleanup system, liquid poison system, control rod drive hydraulic system equipment, core and containment spray systems, and components of electrical equipment. The major safety function of the secondary containment is to minimize ground-level release of airborne radioactive materials by providing controlled, elevated release of the building atmosphere through a filter system under accident conditions.

The Reactor Building has a reinforced concrete substructure founded on sound bedrock. The substructure begins below grade and extends upward to the operating floor. The superstructure above the operating floor consists of structural steel framing supporting the roof system, insulated metal siding, and a 125-ton overhead crane. The metal roof deck is covered with a five-ply tar and felt built-up roof. Pressure relief is provided to prevent collapse of the superstructure due to a break of an emergency cooling system or other primary coolant system line in the Reactor Building. The pressure relief is a metal wall section attached with bolts that are designed to fail with an internal pressure. Precast concrete slabs and uninsulated metal siding are applied to the exterior of the reinforced concrete walls of the Reactor Building for esthetic purposes. These slabs and siding do not form part of the building support or provide any additional measure of leak-tightness for the building. The south and east walls of the Reactor Building are bounded by Turbine Building, and a small portion of the east end north wall is bounded by the Screen and Pump House Building. The adjoining walls of the superstructures are structurally independent of the Reactor Building.

The Reactor Building includes a track bay extension consisting of an air lock, connected to the track bay compartment by a vertical lift inner door and an airtight seal. Containment integrity for the track bay compartment and extension is provided by an outside double swing door, an inside vertical lift door and personnel doors connected by an airtight access passageway. Personnel access into the Reactor Building is controlled from the track bay extension and from the Turbine Building. The track bay extension has a railroad entrance and a personnel access air lock passageway from the outside.

Reactor Building shielding is designed to limit the radiation level in accessible areas during power operation. The biological shield (located around the exterior of the drywell) varies in thickness of concrete for shielding and structural purposes. The biological shield uses bedrock as its main support and is structurally designed to handle the loads of floors, equipment and the higher elevations of the shield itself. Reinforcing steel is included in the design for structural integrity under all

credible conditions. Openings in the biological shield are designed so that they are not aimed directly at the core or major items of equipment in the drywell. In addition, they are either terminated in shielded cubicles or are shielded with steel flanges to reduce radiation levels in accessible areas.

Included within the evaluation boundary of the Reactor Building and determined to be within the scope of license renewal are concrete anchors, concrete embedments, curbs, new fuel storage racks, equipment foundations, hatch covers, plugs, masonry walls, metal siding, pipe whip restraints, reinforced concrete elements, steel components, steel elements, and structural bolting.

Included in the evaluation boundary of the Reactor Building and determined to be not in scope for license renewal are architectural elements, such as non-structural slabs and metal siding, and those in the miscellaneous operational and maintenance support areas that include furniture, drywall partitions and soffits, storage enclosures and suspended ceilings. These nonsafety-related items do not perform a license renewal intended function and their failure will not prevent satisfactory accomplishment of a safety-related function; therefore, they are not in scope for license renewal.

Not included in the evaluation boundary of the Reactor Building are the Primary Containment and associated refueling bellows and seals; the refueling platform, miscellaneous cranes and hoists, including reactor building crane and hoists; other mechanical and electrical systems and components housed within the building; fire barriers; building elevators; and component supports. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities. Component supports, including their respective bolting, are evaluated with the Component Supports Commodity. Fire protection components are evaluated separately within the Fire Detection and Protection System. The refueling platform, reactor building crane and hoists, and miscellaneous cranes and hoists are evaluated with the Cranes, Hoists, and Refueling Equipment System. The spent fuel pool racks are evaluated with the Spent Fuel Pool Cooling and Storage System. Structural commodities, including their associated structural bolting and concrete anchors, are evaluated with the Structural Commodity Group. The Structural Commodity Group evaluates electrical enclosures and raceways (including cable trays and tube track); hazard barriers and elastomers; insulation; and structural miscellaneous components (e.g., metal platforms, grating, stairs, and ladders).

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)
2. Provides protection for safe storage of new and spent fuel. 10 CFR 54.4(a)(1)
3. Controls the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)
4. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory

accomplishment of function(s) identified for 10 CFR 54.4(a)(1).
10 CFR 54.4(a)(2)

5. Provides physical support, shelter, and protection for systems, structures, and components relied upon 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). 10 CFR 54.4(a)(3)
6. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)
7. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
8. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

VI
VI.C
VI.E.2
VII.H
IX.B.6.0
X.J
XII.B.1.2
XV.C

License Renewal Boundary Drawings

SLR-NMP1-S-1

**Table 2.4-3 Reactor Building
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete Elements: Anchors	Structural Support
Concrete Elements: Curbs	Direct Flow
Concrete Elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: All (inaccessible areas)	Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support
Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support
Concrete: Interior	Shelter/Protection, Shielding, Structural Support
Equipment supports and foundations	Structural Support
Fuel Storage Racks (New Fuel Storage Racks)	Structural Support
Hatches/Plugs	Shelter/Protection, Shielding
Masonry walls: Interior	Shelter/Protection, Shielding, Structural Support
Spent fuel pool gates	Water Retaining Boundary
Steel Components: structural steel	Structural Support
Steel Elements: liner, liner anchors, integral attachments (Spent Fuel Pool, Reactor Cavity, Reactor Internals Storage Pit, and Transfer Canal Liners)	Water Retaining Boundary
Structural Miscellaneous - Siding	Shelter/Protection, Structural Pressure Barrier
Structural Miscellaneous - Siding (Blowoff Panels)	Pressure Relief, Shelter/Protection, Structural Pressure Barrier

The aging management review results for these components are provided in:

Table 3.5.2-3 Reactor Building
Summary of Aging Management Evaluation

2.4.4 **Screen and Pump House Building**

Description

The Nine Mile Point Nuclear Station, Unit 1 Screen and Pump House Building consists of the screenhouse superstructure, the screenhouse substructure, the intake tunnel (includes intake structure) and the discharge tunnel (includes discharge structure). The building is located north of the Unit 1 turbine and Reactor Building.

Screenhouse Superstructure:

The superstructure of the screenhouse is a Class II (nonsafety-related) structure. The superstructure wall is physically attached to the Turbine Building and entry into the superstructure is through the Turbine Building. The wall, roofing material and construction of the superstructure is identical to that used for the reactor and Turbine Buildings. Specifically, the superstructure is supported by framed structural steel on a reinforced concrete substructure, which is founded on rock. The superstructure has a flat roof consisting of cellular metal decking covered with insulation and a tar and felt roofing membrane. The roof and its supporting structure are designed to meet applicable codes on exterior loading for wind, snow, and ice. The two bays of the east wall, which are a continuation of the east wall of the turbine auxiliary extension building, are of the same insulated sheet metal construction. The balance of the exterior wall is composed of internally insulated precast concrete panels, corresponding to those in the base of the Reactor Building walls. The precast concrete panels are used for esthetic purposes.

Screenhouse Substructure:

The substructure of the screenhouse is a Class I (safety-related) structure and is entered using the stairs leading from the superstructure. The substructure was built of reinforced concrete and founded on bedrock. The substructure contains channels for the flow of large quantities of raw lake water, gates and stop logs for control of flow, racks (e.g., trash) and screens (i.e., traveling) for cleaning the water, rakes for cleaning the screens, and pumps. There are five vertical gates near the north end of the substructure that separate the channels from the intake and discharge tunnels. These gates are used to provide a flow path to the ultimate heat sink and thus are relied on to support a 10 CFR 54.4(a)(2) function. Two gates separate the intake tunnel from the forebay. A third gate separates the discharge channel from the discharge tunnel with two additional gates separating the discharge channel from the intake tunnel and the forebay from the discharge tunnel. During normal circulation of water drawn from the lake, three gates are open and two gates are closed. There are three sluice gates that control flow to the service water and fire pumps. There is a forebay and a secondary forebay which are connected by three parallel cool water channels. These channels funnel water to the various pumps located throughout the screenhouse.

In addition to the descriptions above, the screenhouse is equipped with a floor-operated electric overhead traveling bridge crane. This crane serves the various functions of placing and removing stop logs, servicing the trash racks, rack rakes and traveling screens, maintenance of the two circulating water pumps and all pumps mounted above the secondary forebay. The service water pumps, their

strainers, and the fire pumps are serviced for maintenance work by overhead beam runs, trolleys, and hoists. The gate hoists are supported by the substructure. Additionally, there is a sodium hypochlorite and chemical tank building attached to the screenhouse which is connected to the chemical injection tanks located inside the screenhouse.

Intake Tunnel:

The intake tunnel is a Class II (nonsafety-related) structure located on the north side of the screen and pump house building. It is constructed of concrete-lined bores through solid rock. Water is drawn offshore from Lake Ontario and enters the intake tunnel through a bell-mouth-shaped inlet. The inlet is surmounted by a hexagonal-shaped intake structure of concrete that is fully submerged. The intake structure is covered with a roof of sheet piling supported by steel beams. The intake structure has six sides for water to enter. Water drops through a vertical concrete shaft to the intake tunnel, through which it flows under the forebay to the screenhouse.

Discharge Tunnel:

The discharge tunnel is a Class II (nonsafety-related) structure and is identical in cross-section to the intake tunnel. The tunnel is located on the north side of the screenhouse and runs angular to the intake tunnel. It is also constructed of concrete-lined bores through solid rock. Water travels through the discharge tunnel and is returned to Lake Ontario through a bell-mouthed outlet surmounted by a hexagonal-shaped discharge structure of concrete. The geometry and construction of the discharge structure closely resemble the intake structure, except for the reduced size. Water is discharged back to the lake through one of six exit ports of the discharge structure. Overall, the discharge tunnel length to the discharge structure is roughly half the length of the intake tunnel to the intake structure.

Class I equipment housed in and supported by the combination Class I and II Screen and Pump House Building structure consists of the emergency service water pumps, the containment spray cooling pumps, and the diesel generator cooling water pumps. Additional equipment housed in these structures includes fire pumps, screen wash pumps, circulating water pumps, hydraulic motor pumps, and non-emergency service water pumps.

Included within the evaluation boundary of the Screen and Pump House Building and determined to be within the scope of license renewal is the screenhouse superstructure, the screenhouse substructure, the intake tunnel (including the intake structure) and the discharge tunnel (including the discharge structure). These structures are classified as a combination of safety-related (Class I) and nonsafety-related (Class II); with the nonsafety-related structures being relied upon in the current licensing basis to support the accomplishment of safety-related functions. This includes the trash rack, sheet piling, reinforced concrete elements, concrete embedments, concrete anchors, equipment supports and foundations, hatches, steel components (structural steel), steel embedments, and masonry walls.

Included in the evaluation boundary of the Screen and Pump House Building and

determined not to be in scope for license renewal are components that are provided for maintenance activities, such as trash rakes. These components do not perform a license renewal intended function and their failure does not prevent satisfactory accomplishment of an intended function. Also, included in the boundary and determined not to be in scope for license renewal are the sodium hypochlorite and chemical tank building.

Not included in the evaluation boundary of the Screen and Pump House Building are cranes, trolleys and hoists, fire protection components, structural commodities, component supports and traveling screens. The cranes, trolleys, and hoists are evaluated with the Cranes, Hoist, and Refueling Equipment System. The fire protection components and barriers are evaluated with the Fire Detection and Protection System. Component supports, including their respective bolting, are evaluated as part of Component Supports Commodity. Structural components used for equipment supports are evaluated with Component Supports Commodity. Structural commodities, including their associated structural bolting and concrete anchors, are evaluated with the Structural Commodity Group. The Structural Commodity Group evaluates electrical enclosures and raceways (including cable trays and tube track); hazard barriers and elastomers; insulation; and structural miscellaneous components (e.g., metal platforms, grating, stairs, metal decking, and ladders). The traveling screens are evaluated with the Circulating Water System. In addition, the mechanical and electrical systems and components housed in or located within the Screen and Pump House Building are evaluated with their respective mechanical and electrical license renewal systems or commodity group.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)
2. Provides Ultimate Heat Sink (UHS) during design basis events. 10 CFR 54.4(a)(1)
3. Provides a source of cooling water for plant safe shutdown. 10 CFR 54.4(a)(1)
4. Provides a source of water for emergency core cooling systems. 10 CFR 54.4(a)(1)
5. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
6. Provides physical support, shelter, and protection for systems, structures, and components relied upon 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). 10 CFR 54.4(a)(3)
7. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)
8. Provides structural support or restraint to SSCs in the scope of license renewal.

10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), 10 CFR 54.4(a)(3)

UFSAR References

III.A.2.4

III.F.1.0

III.F.2.0

X.D.1

X.K.2.2

XVI.D

XVII.C.3.2

Figure III-19

Figure III-20

License Renewal Boundary Drawings

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**Table 2.4-4 Screen and Pump House Building
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete Elements: Anchors	Structural Support
Concrete Elements: Curbs	Direct Flow
Concrete Elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support
Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary
Concrete: All (inaccessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary
Concrete: Basemat, Foundation (accessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary
Concrete: Basemat, Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support
Concrete: Interior (accessible areas)	Shelter/Protection, Structural Support
Concrete: Interior (inaccessible areas)	Shelter/Protection, Structural Support
Equipment supports and foundations	Structural Support
Hatches/Plugs	Shelter/Protection
Masonry walls: Interior	Shelter/Protection, Structural Support
Steel Components (Gates)	Water Retaining Boundary
Steel Components: structural steel	Structural Support
Structural Miscellaneous (Sheet Piles, Floor Plate, Cover Plates)	Shelter/Protection
Structural Miscellaneous - Siding	Shelter/Protection
Trash Racks	Filter
Tunnel (Intake and Discharge Tunnels and Structures)	Direct Flow, Shelter/Protection, Structural Support, Water Retaining Boundary

The aging management review results for these components are provided in:

Table 3.5.2-4 Screen and Pump House Building
Summary of Aging Management Evaluation

2.4.5 **Structural Commodity Group**

Description

The Structural Commodity Group comprises components that share material and environment properties allowing common programs across all in-scope structures to manage their aging effects. Structural commodities include electrical enclosures and raceways; hazard barriers and elastomers; insulation; structural miscellaneous; and structural bolting and concrete anchors associated with these commodities as described below. These structural commodities are installed throughout the station structures. Structural commodities are located in the structures that are within the scope of license renewal.

Electrical Enclosures and Raceways:

The electrical and instrumentation enclosures include components such as electrical panels, frames and racks, cabinets, junction boxes, and enclosures that contain sample stations. Panels, racks, cabinets, and other enclosures within the scope of license renewal include those items that perform license renewal intended functions for shelter, protection, and structural support for electrical and instrumentation equipment and components within the scope of license renewal. Security system panels designed with seismic anchorage are also included in this category.

Raceways include components such as cable trays, cable tray covers, rigid and flexible electrical conduits and fittings, wiring gutters, and tube track. These provide license renewal intended functions of structural support, shelter, and protection for various electrical and control system power, control, and instrumentation cables and tubing that are within the scope of license renewal.

Hazard Barriers and Elastomers:

Hazard barriers and elastomers included within the scope of this commodity group include those hazard barriers that perform intended functions other than fire barrier and that are not evaluated with the overall structure, such as a floor or wall. Hazard barriers include penetration seals, penetration sleeves, personnel access doors, and missile, radiation, and spray shields that perform various license renewal intended functions for shelter and protection, flood barrier, structural pressure barrier, and high-energy line break shielding for structures that are within the scope of license renewal.

Inlet and outlet duct penetrations through the Reactor Building walls are sealed against leakage. A steel pipe sleeve is integrally cast in the concrete, and the outer end of the sleeve has a gasketed flange which connects to the first isolation valve in the ventilation system. To prevent infiltration of potentially contaminated air, main control room penetrations are sealed to maintain a positive pressure to the Turbine Building.

Doors and access openings to the Reactor Building have been designed to prevent breaching secondary containment integrity and analyzed to assure that air leakage will be within specifications. The track bay compartment and extension are

provided with an outside double swing door, an inside vertical lift door and personnel doors connected by an airtight access passageway. Interior doors with air locks are provided in the south wall of the Reactor Building leading into the Turbine Building. To prevent infiltration of potentially contaminated air, doors to the main control room are weather-stripped. Several passages between spaces in the radwaste solidification and storage building are equipped with sliding shield doors to mitigate radiation.

Concrete barriers surround the areas near the turbine generator, condenser, and related auxiliary equipment, that contain high energy steam lines. These offer sufficient protection against internally generated missiles or pipe whip effect on systems and piping outside this area. Within the area of these barriers, there are no piping systems or other systems which could affect safe shutdown. Structural shielding around selected components protects personnel from exposures above established limits. Standard concrete is used for the major portion of the shielding; permanent lead shielding is used where necessary.

This evaluation category also includes roofing assemblies. Roofing within the scope of license renewal includes those roofs that perform license renewal intended functions for shelter and protection for structures within the scope of license renewal. The Turbine Building and Reactor Building roofs and their supporting structures are designed to withstand a loading of snow or ice that comply with applicable codes.

Seals, gaskets (including elastomers), compressible joints, and moisture barriers within the scope of license renewal include those items that perform license renewal intended functions such as shelter and protection, structural pressure barrier, and flood barrier for structures and components that are within the scope of license renewal. Elastomer components within the scope of license renewal include expansion joint seals, gaskets at hatches and doors, spent fuel pool gate seals, and metal siding gap seals. To ensure a proper gap for drywell growth under incident pressure and temperature conditions, shop-fabricated fiberglass forms were used to retain the concrete biological shield surrounding the drywell. The form panels were shimmed in place with compressible polyurethane strips; joints were sealed with fiberglass strip and polyester resin for leak tightness. Pre-formed rubber water stops are incorporated in the concrete construction joints for water-tightness and resilient sealing compositions containing organic acrylic polymers with enduring elasticity are used for waterproofing the Turbine Building floor slab, along the Reactor Building walls and the north wall of the waste disposal building, and around the main stack. Interlocking joints in the insulated metal siding panels that form the Reactor Building superstructure, the Turbine Building superstructure, and the east wall of the main control room are sealed with a synthetic elastomer caulking material.

Insulation:

Thermal insulation and jacketing materials, within the scope of license renewal, are those that are used in conjunction with electric heat trace on in scope piping and mechanical components to ensure minimum temperatures for system operation to meet system intended functions. Other thermal insulation functions, such as personnel protection, for thermal efficiency of plant systems, and to prevent

sweating of piping and other mechanical components due to condensation, are not intended functions within the scope of subsequent license renewal.

Structural Miscellaneous:

The structural miscellaneous evaluation category includes platforms, catwalks, grating, stairs, ladders, steel curbs, handrails, permanent scaffolding, decking, and sump covers. These steel components and other similar components are installed throughout station structures. Some components are exposed to the outdoor environment. The components that perform license renewal intended functions such as structural support or shelter and protection are located within structures that are within the scope of license renewal.

This evaluation category also includes fixed louvers, and vents. Fixed air louvers and vents have been installed based on ventilation requirements for size, velocity, location, type, and security conditions. Louvers installed in exterior walls of structures within the scope of license renewal are also in scope for license renewal. Prefabricated vents installed in the Turbine Building roof and sidewall facilitate smoke removal in the event of fire. Exterior wall louvers and vent openings are protected by weather hoods or bird and insect screening.

Structural Bolting and Concrete Anchors:

Bolting and anchors within the scope of license renewal includes fasteners that provide structural support for structural commodities within the scope of license renewal.

Included within the evaluation boundary of the Structural Commodity Group and determined to be within the scope of license renewal are the electrical enclosures and raceways, hazard barriers and elastomers, insulation, structural miscellaneous, and associated structural bolting and concrete anchors that are located in structures and areas with mechanical or electrical components that are in scope for license renewal.

Included in the evaluation boundary of the Structural Commodity Group and determined to be not in scope for license renewal are the electrical enclosures and raceways, hazard barriers and elastomers, insulation, structural miscellaneous, and associated structural bolting and concrete anchors that are installed in those structures and areas where there are no mechanical or electrical components in scope for license renewal. Materials used in construction of the drywell air gap (e.g., polyurethane tape) are not in scope as they do not serve an intended function for license renewal.

Not included in the evaluation boundary of the Structural Commodity Group are hatches, concrete equipment foundations, pipe whip restraints, columns, concrete embedments, and concrete anchors used for component supports. These commodities are evaluated separately with the license renewal structure or commodity group that contains them. Structural components used for equipment supports are evaluated with the Component Supports Commodity. The fire barrier functions of components such as fire rated doors, dampers, fire rated enclosures, fire proofing material, penetration seals, and the fire protection function of walls

and slabs are evaluated with the Fire Detection and Protection System. Containment air locks, equipment hatches, penetration sleeves, and associated seals, gaskets, and moisture barriers comprising the drywell and torus containment boundary are evaluated with the Primary Containment. The reactor shield wall inside the drywell is evaluated with the Primary Containment; the biological shield wall that encloses the drywell for shielding purposes is evaluated with the Reactor Building. In addition, the mechanical and electrical systems and components housed in or located within electrical and instrumentation enclosures and raceways are evaluated with their respective mechanical and electrical license renewal systems or commodities group.

The structural commodities within the scope of license renewal are not shown on the license renewal boundary drawings since these commodities are included within structures in scope for license renewal.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)
2. Controls the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)
3. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
4. Provides physical support, shelter, and protection for systems, structures, and components relied upon 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). 10 CFR 54.4(a)(3)
5. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)
6. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
7. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

III.A
III.B
III.C

III.D
III.F
III.G
III.I
V.B
VI.B
VI.C
VI.E
VIII.A
IX.B
XI.C
XII.A
XII.B
XVI.B
XVI.D

License Renewal Boundary Drawings

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**Table 2.4-5 Structural Commodity Group
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Structural)	Structural Support
Cable Trays and Gutters	Shelter/Protection, Structural Support
Concrete Elements: Anchors	Structural Support
Conduit	Shelter/Protection, Structural Support
Doors	Flood Barrier, HELB/MELB Shielding, Shelter/Protection, Shielding, Structural Pressure Barrier
Expansion Joints	Expansion/Separation
Insulation - Thermal	Thermal Insulation
Insulation Jacketing - Thermal	Thermal Insulation Jacket Integrity
Panels, Racks, Frames, Cabinets, and Other Enclosures	Shelter/Protection, Structural Support
Penetration sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support, Water retaining boundary
Roofing	Shelter/Protection
Seals, gaskets, and moisture barriers (caulking, flashing and other sealants)	HELB/MELB Shielding, Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Water retaining boundary
Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support
Tube Track	Shelter/Protection, Structural Support

The aging management review results for these components are provided in:

**Table 3.5.2-5 Structural Commodity Group
Summary of Aging Management Evaluation**

2.4.6 Turbine, Waste Handling, and Admin. Structures

Description

The Turbine, Waste Handling, and Admin. Structures comprise the administration building extension, administration building original (operations office building), auxiliary control room, diesel generator rooms, main control room, main stack, offgas building, radwaste solidification and storage building, technical support center, Turbine Building, and waste disposal building. Descriptions of the structures along with their functions are provided below.

Administration Building Extension:

The purpose of the administration building extension is to provide office space and other supporting facilities for various station personnel groups. The basement of the administration building extension houses the onsite technical support center. The administration building extension houses NFPA 805 components.

The administration building extension is designed as a Class II structure. A portion of the administration building extension is located in proximity to the diesel generator rooms requiring an upgraded seismic design. The administration building extension is designed to accommodate the same seismic loads as the main control room and diesel generator rooms.

The administration building extension is bounded by the Turbine Building to the northwest and the administration building original to the west.

The building is a steel-framed structure with cellular metal and concrete floors and exterior walls of insulated precast concrete slabs and has three floors. The precast concrete panels are used for esthetic purposes.

Administration Building Original (Operations Office Building):

The purpose of the administration building original (operations office building) is to provide office space and other supporting facilities for various station personnel groups. The administration building original includes the foam room which houses NFPA 805 components.

The administration building original is designed as a Class III structure.

The administration building original is a one and two-story steel framed structure bounded by the Turbine Building to the north.

Main Control Room and Auxiliary Control Room:

The purpose of the main control room and auxiliary control room is to provide a location from which actions to maintain safe operational status of the station can be controlled. The rooms contain the majority of the controls and switching equipment operation. The main control room and auxiliary control room provide controls for normal operation and for shutdown of the station under abnormal conditions. The main control room and auxiliary control room provide radiation protection for personnel during accident conditions. The main control room and auxiliary control

room provide structural support for safety-related components. The main control room and auxiliary control room house systems and components necessary to address Abnormal Operating Transients (AOT), Fire Protection (including NFPA 805), components for Station Blackout (SBO) coping and recovery, Anticipated Transients without Scram (ATWS), and Equipment Qualification (EQ) components.

The main control room and auxiliary control room are designed as Class I structures.

The main control room and auxiliary control room are located in the southeast corner of the Turbine Building, and house the equipment, instrumentation and cables used to operate plant equipment. The main control room is bounded by the administration building extension to the east; the administration building original to the south; the Turbine Building to the west; and the control room break area, instrumentation and control office area, and diesel generator rooms to the north. The auxiliary control room is directly below the main control room.

The structural steel enclosing the main control room and the auxiliary control room is supported by concrete walls and concrete foundations bearing on and keyed into sound rock. The control room walls, roof and floors are framed with structural steel. The west and north interior walls are reinforced concrete. The east wall is enclosed with insulated metal wall panels. This wall is separated from the administration building extension by a small rattle space. The south interior wall consists of concrete blocks laid with steel-reinforced mortar joints. The slab immediately above the main control room is pinned to the walls and provides radiation shielding and consists of poured-in-place reinforced concrete supported on structural steel beam framing. The main control room floor is poured-in-place reinforced concrete on metal decking.

Habitability systems are provided to ensure that control room operators can remain in the main control room, operate the station safely under normal conditions, and maintain the station in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge.

Diesel Generator Rooms:

The purpose of the diesel generator rooms is to provide structural support, shelter, and protection for the two standby emergency diesel generators and associated controls and support equipment. The diesel generator rooms house systems and components necessary to address AOT, NFPA 805, components for SBO coping and recovery, and EQ components.

The diesel generator rooms, which include the roll-up doors as an integral part of the structure, are designed as Class II structures. The diesel generator support foundations are designed as Class I structures.

The diesel generator rooms are located within the Turbine Building. The diesel generator rooms are bounded by the offgas building to the north, the turbine auxiliary equipment area to the west, the main and auxiliary control rooms to the south and the administration building extension to the southeast.

The diesel generator rooms consist of a combination of reinforced concrete walls and reinforced hollow masonry block walls.

Main Stack:

The purpose of the main stack is to be used as an elevated point for gaseous releases providing a high degree of dilution for routine or accidental station effluents.

The main stack is designed as a Class I structure.

The main stack is located east of the northeast corner of the Reactor Building.

The main stack is a freestanding reinforced-concrete chimney. It is a tapered monolithic reinforced-concrete tube resting on a concrete base which extends to sound bedrock. From this base it rises through the turbine auxiliaries building extension from which it is completely isolated structurally.

Offgas Building:

The purpose of the offgas building (OGB) is to house equipment and controls associated with the Condenser Air Removal and Off-gas System and includes EQ components and NFPA 805 components.

The OGB is designed as a Class I structure.

The OGB is bounded by the waste disposal building to the north, the Turbine Building to the west, the diesel generator rooms to the south, and the radwaste solidification and storage building to the northeast.

The substructure is constructed of cast-in-place reinforced concrete and is founded on bedrock. The superstructure is structural steel frame with insulated exterior metal walls and masonry block. The interior walls of the substructure are of cast-in-place concrete and concrete block. Structural floors are poured-in-place concrete slabs.

Radwaste Solidification and Storage Building:

The purpose of the radwaste solidification and storage building (RSSB) is to provide onsite storage of low-level radioactive waste. During normal operation, maintenance, and loading and unloading operations, the structure provides sufficient environmental isolation.

The RSSB is designed as a Class I structure.

The RSSB is located to the east of, and directly adjacent to, the OGB and the Waste Disposal Building.

The foundation mat (founded on bedrock), structural walls, columns, floors and roof of the RSSB are classified as primary structural elements and are seismically designed to withstand the effects of an operating basis earthquake (OBE).

Secondary structural elements (e.g., platforms; catwalks; pipe, equipment, and vessel supports; and internal masonry walls) are classified as nonseismic-resistant items and are designed by conventional methods.

Turbine Building:

The purpose of the Turbine Building is to provide structural support, shelter, and protection for the equipment located inside.

The Turbine Building is designed as a Class II structure.

The Turbine Building houses the following Class I Equipment, Systems, or Areas: diesel generator support structure, main control room, auxiliary control room, battery room, battery board room and the supporting steel structure for the emergency condenser, makeup, and demineralized water tanks. The Turbine Building houses systems and components necessary to address AOTs, NFPA 805, SBO coping and recovery, and ATWS. The Turbine Building also houses the turbine generator and associated power generation equipment.

The Turbine Building is bounded by the Reactor Building to the north, the administration building extension to the southeast, the administration building original to the south, and the offgas building and waste disposal building to the northeast.

The reinforced concrete Turbine Building foundations are supported by concrete column piers founded on bedrock. The Turbine Building superstructure consists of an enclosed structural steel frame. The lower portion of building is covered with insulated precast concrete wall panels. The precast concrete panels are used for esthetic purposes. Above the precast concrete panel to the roof, the building is enclosed with insulated metal siding. To prevent failure of the superstructure due to a steam line break, a portion of the wall area has been attached with bolts that will fail, thus relieving internal pressure.

Waste Disposal Building:

The purpose of the waste disposal building is to house the systems and components for processing radioactive waste. The waste disposal building houses NFPA 805 components.

The waste disposal building is designed as a Class I structure.

The waste disposal building is located to the west of the RSSB, to the north of the OGB, to the east of the turbine auxiliary extension building, and to the south of the screen and pump house building.

The waste disposal building has a poured-in-place reinforced concrete building substructure which is founded on bedrock. The superstructure frame is made of fabricated steel. The exterior facing of the superstructure walls is of sheet metal, attached either to an exterior shielding wall or to insulated cellular sheet metal wall. The interior walls of the substructure are of cast-in-place concrete and those for the superstructure are either cast-in-place or made of concrete masonry units.

Structural floors are poured-in-place concrete slabs. The waste disposal building has a flat roof consisting of a cellular metal deck covered with insulation and a bitumen and felt roofing membrane.

Included within the evaluation boundary of the Turbine, Waste Handling, and Admin. Structures and determined to be within the scope of license renewal are the administration building extension, administration building original, auxiliary control room, diesel generator rooms, main control room, main stack, offgas building, radwaste solidification and storage building, Turbine Building, the waste disposal building, and the foam room (within the administration building original).

Included in the evaluation boundary of the Turbine, Waste Handling, and Admin. Structures and determined to be not in scope for license renewal is the technical support center as well as architectural elements in the miscellaneous operational and maintenance support areas that include furniture, drywall partitions and soffits, storage enclosures, and suspended ceilings which do not perform an intended function for license renewal.

Not included in the evaluation boundary of the Turbine, Waste Handling, and Admin. Structures are component supports, snubbers, and similar type components; fire protection components; and structural commodities. Component supports, snubbers, and similar type components; including their respective bolting; are evaluated as part of Component Supports Commodity. The fire protection components and barriers are evaluated separately within the Fire Detection and Protection System. Structural commodities, including their associated structural bolting and concrete anchors, are evaluated with the Structural Commodity Group. The Structural Commodity Group evaluates electrical enclosures and raceways (including cable trays and tube track); hazard barriers and elastomers; insulation; and structural miscellaneous components (e.g., metal platforms, grating, stairs, and ladders). In addition, mechanical and electrical systems and components housed in or located within the Turbine, Waste Handling, and Admin. Structures are evaluated with their respective mechanical and electrical license renewal system or commodity group.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)
2. Controls the potential release of fission products to the external environment so that offsite consequences of design basis events are within acceptable limits. 10 CFR 54.4(a)(1)
3. Provides for the discharge of treated gaseous waste to meet the requirements of 10 CFR 50.67 or 10 CFR 100. 10 CFR 54.4(a)(1)
4. Provide centralized area for control and monitoring of nuclear safety-related equipment. 10 CFR 54.4(a)(1)
5. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)

6. Provides physical support, shelter, and protection for systems, structures, and components relied upon 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). 10 CFR 54.4(a)(3)
7. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)
8. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transients without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
9. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

III.A
 III.B
 III.C
 III.D
 III.E.1
 III.G
 III.I
 VI
 VII
 IX.B.6.0
 X.K
 XII.A
 XV.B
 XVI.D

License Renewal Boundary Drawings

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**Table 2.4-6 Turbine, Waste Handling, and Admin. Structures
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Structural)	Structural Support
Bolting (Structural) (Stack)	Structural Support
Concrete Elements: Anchors	Structural Support
Concrete Elements: Anchors (Stack)	Structural Support
Concrete Elements: Curbs	Direct Flow
Concrete Elements: Embedments	Structural Support
Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Support
Concrete: Above-grade exterior (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support
Concrete: Above-grade exterior (inaccessible areas)	Gaseous Release Path, Shelter/Protection, Shielding, Structural Support
	Shelter/Protection, Shielding, Structural Support
Concrete: Above-grade exterior (inaccessible areas) (Stack)	Gaseous Release Path, Shelter Protection, Structural Support
Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support
Concrete: All (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support
Concrete: All (inaccessible areas)	Direct Flow, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support
Concrete: All (inaccessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support
Concrete: Foundation (accessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support
Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support
Concrete: Foundation (inaccessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support
Concrete: Interior	Flood Barrier, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support

Component Type	Intended Function
Equipment supports and foundations	Structural Support
Hatches/Plugs	Shelter/Protection, Shielding
Masonry walls: Interior	Shelter/Protection, Shielding, Structural Support
Steel Components: structural steel	Structural Support
Structural Miscellaneous - Siding	Shelter/Protection
Structural Miscellaneous - Siding (Blowoff Panels)	Pressure Relief, Shelter/Protection
Structural Miscellaneous - Vent	Filter

The aging management review results for these components are provided in:

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures
Summary of Aging Management Evaluation

2.4.7 Yard Structures

Description

The Yard Structures includes the 345kV switchyard, the emergency diesel generator (EDG) fuel oil storage tank foundations, the 115kV switchyard, nitrogen (N₂) and hydrogen storage tank foundations, the radwaste pipe tunnel extension, the rock dike and a portion of the revetment-ditch system, the buried electrical duct banks from the Turbine Building to Reactor Building, earthen berms, valve pits, miscellaneous in scope yard structures and miscellaneous not in scope yard structures. These structures are in various locations throughout the site. A description of each structure is provided below.

345kV Switchyard:

The 345kV switchyard contains nonsafety-related reinforced concrete foundations and steel structures that support equipment and high voltage lines for the 345kV system. These support structures are relied upon by the 345kV system to support the terminals, transformers, transmission line cables, switches, and relays that route power from the main generator to the power grid. The foundation and steel support structures are located throughout the 345kV switchyard. The 345kV switchyard is located south of the Turbine Building and parallel to the 115kV switchyard. The 345kV switchyard is required to support the fire protection function.

EDG Fuel Oil Storage Tank Foundations:

The safety-related EDG fuel oil storage tank foundations provide support for two storage tanks located outside of the diesel generator rooms within the Turbine Building. These safety-related tanks are relied upon to provide storage for fuel oil that is used by two EDGs and the diesel-driven fire pump. Each tank is buried and supported by reinforced concrete pads. There is also a concrete spill pad around the fill points for a spill collection tank. The spill collection tank is buried next to the EDG fuel oil storage tanks.

115kV Switchyard:

The 115kV switchyard includes the nonsafety-related reinforced concrete foundations and steel structures that support the equipment and high voltage lines in the 115kV switchyard. These support structures are relied on by the 115kV system to support the portals, transformers, transmission line cables, switches, and relays that provide power for station startup and supply for electrical auxiliaries. The electrical equipment support foundations and steel support structures are located throughout the 115kV switchyard. The 115kV switchyard is located southwest of the Turbine Building and parallel to the 345kV switchyard. The 115kV switchyard is required to support fire protection and station blackout functions.

Nitrogen (N₂) and Hydrogen Storage Tank Foundations:

The safety-related nitrogen and hydrogen storage tank foundations provide support for three tanks: one 11,410-gallon nitrogen tank (includes nitrogen vaporizer), one 4,000-gallon nitrogen tank and one hydrogen storage tank area with multiple

cylinders stacked on a storage rack. The nitrogen tanks are relied on by the containment inerting system to provide nitrogen supply for purging of the primary containment atmosphere. The nitrogen supply system also relies on the nitrogen tanks to supply nitrogen under accident conditions. Both nitrogen storage tanks and nitrogen vaporizer are installed on separate reinforced concrete pads with one tank (11,410-gallon) and nitrogen vaporizer located north of the Reactor Building and the other tank (4,000-gallon) located west of the Reactor Building. The hydrogen tank area is relied on to provide hydrogen to the "hydrogen supply for generator" system and is required for fire protection and station blackout functions. The hydrogen storage tank foundation is constructed of reinforced concrete. The hydrogen tank area is located west of the Reactor Building and slightly south of the 4000-gallon nitrogen tank.

Radwaste Pipe Tunnel Extension:

The nonsafety-related radwaste pipe tunnel extension provides protection from radioactive piping. The tunnel is constructed of concrete and supports shielding which acts as a barrier to prevent the spread of radioactivity within the station or to outside areas. The radwaste pipe tunnel extension is located below grade and extends from the southeast corner of the radwaste solidification and storage building (RSSB) towards the Unit 2 screenwell building, ultimately connecting to the Unit 2 radwaste building. Therefore, part of this tunnel is in the Unit 1 RSSB and the Unit 2 radwaste building.

Unit 1 Rock Dike and Applicable Portion of Unit 2 Revetment-Ditch System:

A nonsafety-related rock dike, which includes a ditch, protects the Unit 1 shoreline and buildings from lake wave action and ice accumulation. The dike is located north of Unit 1 and runs east-west along Lake Ontario. The dike is constructed of rock from the original site excavation and contains large rocks on the lakeside face. The Unit 1 dike is relied on to support a 10 CFR 54.4(a)(2) function. Additionally, Unit 1 is protected by a portion of the Unit 2 safety-related revetment-ditch system. However, the revetment-ditch system does not provide a safety-related function for Unit 1. The revetment-ditch system considered in this evaluation replaced a portion of the Unit 1 rock dike, which was shortened when Unit 2 was constructed. The Unit 2 revetment-ditch system is located along the lakeshore and includes a ditch located below the top of the revetment. The revetment-ditch system is constructed of backslope rock armor units, dolos concrete armor on the front slope, underlayers, and granular filters. The Unit 1 rock dike and the Unit 2 revetment-ditch system are connecting structures.

Buried Electrical Duct Banks from Turbine Building to Reactor Building:

The safety-related buried electrical duct banks consist of rows of bars containing steel conduit ducts encased in concrete. The concrete protects the duct banks which run from the north wall of the Turbine Building to the Reactor Building.

Earthen Berms:

Earthen berms are located around the perimeter of the site to provide flood protection. The earthen berms are not credited in the Unit 1 licensing basis and are therefore, not in scope for license renewal.

Valve Pits:

The nonsafety-related emergency diesel generator fuel oil transfer valve pit provides shelter and protection for safety-related valves and piping. The valve pit consists of a reinforced concrete structure that is buried below grade and has a removable cover to allow for plant personnel access. The valve pit is located next to the east wall of the diesel generator rooms, which are within the Turbine Building. This valve pit is relied on to support a 10 CFR 54.4(a)(2) function.

Additionally, there is a service water valve pit located near the sodium hypochlorite and chemical tank building and a city water meter valve pit located next to the west security building. Both valve pits are nonsafety-related and do not perform a license renewal function.

Miscellaneous In Scope Yard Structures:

The yard area contains miscellaneous structures that are not tied to the structures identified above but are within the scope of license renewal. These include manholes containing in scope electrical components, transformer foundations and associated bus duct supports, and transmission tower foundations that are located within the protected area but outside of the 115 kV and 345 kV switchyards.

Miscellaneous Not In Scope Yard Structures:

The yard area contains miscellaneous nonsafety-related civil features that are not tied to any of the structures identified above. These include light pole foundations, a cement storage silo foundation, and miscellaneous foundations.

Included within the evaluation boundary of the Yard Structures and determined to be within the scope of license renewal is the 345kV switchyard, the EDG fuel oil storage tank foundations (excluding the spill collection tank), the 115kV switchyard, the nitrogen (N₂) and hydrogen storage tank foundations, the rock dike and applicable portion of the Unit 2 revetment-ditch system, the buried electrical duct bank from the Turbine Building to the Reactor Building, and the emergency diesel generator fuel oil transfer valve pit and miscellaneous in scope yard structures. These structures are classified as a combination of safety-related and nonsafety-related; with the nonsafety-related structures being relied upon in the current licensing basis to support the accomplishment of safety-related functions.

Included in the evaluation boundary of the Yard Structures and determined not to be in scope for license renewal are the earthen berms, the spill collection tank, the radwaste pipe tunnel extension, the service water and city water meter valve pits, and the miscellaneous not in scope yard structures.

Not included in the evaluation boundary of the Yard Structures are miscellaneous not in scope structures, fire protection components, structural commodities, and component supports. The miscellaneous structures including various not in scope buildings are evaluated with the miscellaneous not-in-scope structures. The fire protection components and barriers are evaluated with the Fire Detection and Protection System. Component supports, including their respective bolting, are evaluated as part of Component Supports Commodity. Structural components used for equipment support are evaluated with Component Supports Commodity.

Structural commodities, including their associated structural bolting and concrete anchors, are evaluated with the Structural Commodity Group. The Structural Commodity Group evaluates electrical enclosures and raceways (including cable trays and tube track); hazard barriers and elastomers; insulation; and structural miscellaneous components (e.g., metal platforms, grating, stairs, and ladders). In addition, the mechanical and electrical systems and components housed in or located in specific Yard Structures are evaluated with their respective mechanical and electrical license renewal systems or commodity group. For first license renewal the administrative building extension was evaluated in Essential Yard Structures; for subsequent license renewal the administration building extension is evaluated as part of the Turbine, Waste Handling, and Admin. Structures.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems, structures, and components. 10 CFR 54.4(a)(1)
2. Provides physical support, shelter, and protection for nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
3. Provides structural support or restraint to SSCs in the scope of license renewal. 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), 10 CFR 54.4(a)(3)
4. Provides physical support, shelter, and protection for systems, structures, and components relied upon 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). 10 CFR 54.4(a)(3)
5. Provides physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

UFSAR References

III.A.3
III.I.3
VI.C.2.1
VII.G.2.1
IX.B.1.1
IX.B.1.2
IX.B.4.1
IX.B.6

License Renewal Boundary Drawings

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**Table 2.4-7 Yard Structures
Components Subject to Aging Management Review**

Component Type	Intended Function
Bolting (Structural)	Structural Support
Concrete Elements: Anchors	Structural Support
Concrete Elements: Embedments	Structural Support
Concrete: (Tanks) Foundation (accessible areas)	Structural Support
Concrete: (Tanks) Foundation (inaccessible areas)	Structural Support
Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support
Concrete: All	Structural Support
Concrete: All (accessible areas)	Shelter/Protection, Structural Support
Concrete: All (inaccessible areas)	Shelter/Protection, Structural Support
Concrete: Below-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support
Concrete: Foundation (accessible areas)	Structural Support
Concrete: Foundation (inaccessible areas)	Structural Support
Concrete: Interior	Shelter/Protection, Structural Support
Duct Banks	Shelter/Protection
Steel Components: structural steel	Structural Support
Structural Miscellaneous (Unit 1 Rock Dike and Applicable Portion of the Unit 2 Revetment-Ditch System)	Shelter/Protection
Structural Miscellaneous (Valve Pit Cover)	Shelter/Protection

The aging management review results for these components are provided in:

**Table 3.5.2-7 Yard Structures
Summary of Aging Management Evaluation**

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL

The determination of electrical systems that fall within the scope of license renewal is made through the application of the process described in Section 2.1. The results of the electrical systems scoping review are contained in Section 2.2.

Subsection 2.1.6.1 provides the screening methodology for determining which electrical components and commodity groups within the scope of 10 CFR 54.4 meet the requirements contained in 10 CFR 54.21(a)(1). The electrical commodity groups that meet those screening requirements are identified in this section. These identified electrical commodity groups consequently require an aging management review.

As described in Subsection 2.1.6.1, the screening was performed on a commodity group basis for the in scope electrical and I&C systems as well as the electrical and I&C component types associated with in scope mechanical systems listed in Table 2.2-1.

Components which support or interface with electrical and I&C components, for example, raceways, cable trays, conduits, tube track, instrument tubing, racks, panels, cabinets and enclosures for electrical equipment and instrumentation are assessed as part of the Component Supports Commodity in Section 2.4.1.

2.5.1 ELECTRICAL SYSTEMS

The results of the electrical system scoping review are contained in Section 2.2. Additional system details are included in the UFSAR Sections referenced in Table 2.2-1, Plant Level Scoping Results. In addition to the electrical and I&C systems and components, certain switchyard components are credited to restore offsite power following a station blackout (SBO) and other switchyard components are credited to provide a back feed current path to the 4.16KV AC power boards for fire protection during non-power operations (NPO). The boundary for offsite power restoration following an SBO is shown in a simplified diagram in Figure 2.1-2.

2.5.2 ELECTRICAL COMMODITIES

2.5.2.1 Identification of Electrical Commodities

The first step of the screening process for electrical commodities is to identify the electrical components and commodities within the electrical, I&C, and mechanical systems based on plant design documentation, drawings, and the NMP1 Equipment List, as well as by interfacing with the parallel mechanical and civil screening efforts. The electrical components and commodities identified at NMP1 are listed below. This list includes electrical components and commodities identified in NUREG-2192, Table 2.1-6, as applicable at NMP1.

Electrical Components and Commodities for In Scope Systems:

- Alarm Units
- Analyzers
- Annunciators

- Batteries
- Cable Connections (Metallic Parts)
- Cable Tie Wraps
- Chargers
- Circuit Breakers
- Communication Equipment
- Computers
- Connection Contacts
- Controllers
- Converters
- Electric Heaters
- Electrical Controls and Panel Internal Assemblies
- Electrical equipment subject to 10 CFR 50.49 EQ requirements
- Electrical Penetrations
- Elements, RTDs, Sensors, Thermocouples, Transducers
- Fuse Holders
- Fuses
- Generators, Motors
- Heat Trace
- High Voltage Electrical Insulators
- Indicators
- Insulated Cables and Connections
- Inverters
- Isolators
- Light Bulbs
- Loop Controllers
- Metal Enclosed Bus
- Meters
- Motor Generator Sets
- Power Supplies
- Radiation Monitors
- Recorders

- Regulators
- Relays
- Signal Conditioners
- Solenoid Operators
- Solid State Devices
- Splices
- Surge Arresters
- Switches
- Switchgear, Load Centers, Motor Control Centers, Distribution Panels
- Switchyard Bus and Connections
- Terminal Blocks
- Transformers
- Transmission Conductors
- Transmission Connections
- Transmitters
- Uninsulated Ground Conductors

2.5.2.2 Application of Screening Criterion 10 CFR 54.21(a)(1)(i) to the Electrical Components and Commodities

Following identification of the 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 commodities were determined to meet the screening criteria of 10 CFR 54.21(a)(1)(i):

- Cable Connections (Metallic Parts)
- Electrical Penetrations
- Cable Tie Wraps
- Uninsulated Ground Conductors
- Fuse Holders (Not Part of Active Equipment)
- High Voltage Electrical Insulators
- Insulation for Electrical Cables and Connections
- Metal Enclosed Bus
- Switchyard Bus and Connections
- Transmission Conductors

- Transmission Connections
- Passive electrical equipment subject to 10 CFR 50.49 EQ requirements

2.5.2.3 **Elimination of Electrical Commodity Groups with No License Renewal Intended Functions**

The following electrical commodities were determined to not have a license renewal intended function:

Cable Tie Wraps

Tie wraps are used in cable installations as cable ties. Cable ties hold groups of cables together for restraint and ease of maintenance. Cable ties are used to bundle wires and cables together to keep the wire and cable runs neat and orderly. Cable ties are used to restrain wires and cables within raceways to facilitate cable installation. There are no current license basis requirements for NMP1 that cable tie wraps remain functional during and following design basis events. Cable ties are not credited for maintaining cable ampacity, ensuring maintenance of cable minimum bending radius, or maintaining cables within vertical raceways at NMP1. The seismic qualification of cable trays does not credit the use of cable ties. Cable tie wraps are not credited in the NMP1 design basis in terms of any 10 CFR 54.4 intended function. Therefore, cable tie wraps are not within the scope of license renewal and are not subject to aging management review.

Fuse Holders (Not Part of Active Equipment): Metallic Clamps, Insulation Material

The fuse holder commodity includes both the insulation portion of the fuse holder and the metallic clamp portion of the fuse holder.

A systematic review was performed to determine if there were fuse holders that were in scope for NMP1 subsequent license renewal. The review used plant documents, controlled drawings, and the plant equipment database to identify individual Fuse Holders (Not Part of Active Equipment): Metallic Clamps, Insulation Material. A comprehensive fuse holder list was assembled. A scoping determination was made considering if the fuse holder:

- Was installed in active equipment, or
- Performed a license renewal intended function.

The review determined there are no fuse holders performing a license renewal intended function and located outside of active equipment at NMP1. There are no NMP1 Fuse Holders (not part of active equipment): Metallic Clamps, Insulation Material in scope for NMP1 subsequent license renewal and therefore, are not subject to aging management review.

Uninsulated Ground Conductors

The uninsulated ground conductor commodity 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 license renewal and are not subject to aging management review.

2.5.2.4 Application of Screening Criteria 10 CFR 54.21(a)(1)(ii) to Electrical Commodities

The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to the specific commodities 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 (EQ) Program. This is acceptable 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 (EQ) of Electric Components program. The remaining commodities, all or part of which are not in the EQ Program, require aging management review and are discussed below.

2.5.2.5 Electrical Commodities Subject to Aging Management Review

The electrical commodities subject to aging management review are identified in Table 2.5.2-1, along with the associated intended functions. These electrical commodities are further described below.

2.5.2.5.1 Cable Connection (Metallic Parts)

The Cable Connectors (Metallic Parts) commodity includes metallic portions of cable connections that are not included in the EQ Program. The metallic connections evaluated include splices, threaded connectors, compression-type termination lugs, and terminal blocks. Therefore, Cable Connections (Metallic Parts) meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to aging management review.

2.5.2.5.2 Electrical Penetrations

Environmentally qualified electrical penetrations that are evaluated as a time-limited aging analysis, are excluded from aging management review based on Section 2.5.2.4 above and are managed by the Environmental Qualification (EQ) of Electric Components (B.3.1.3) program. For the remainder of the electrical penetrations, the electrical continuity of electrical penetration pigtailed and associated connections that could potentially be exposed to an adverse localized environment are included in for Insulation Material for Electrical Cables and Connections. The shelter, protection and pressure boundary intended functions of electrical penetrations are included in Primary Containment.

2.5.2.5.3 High Voltage Electrical Insulators

The high voltage insulators commodity group provides insulation for switchyard bus, overhead transmission conductors, and active switchyard components. These insulators are part of the 345kV and 115kV switchyard circuits that supply power from the electric utility transmission system to plant buses, including power circuits that are credited for recovery of offsite power following a station blackout event and power circuits credited for fire protection during non-power operations. High Voltage Insulators are not included in the EQ program. Therefore, high voltage Insulators meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

2.5.2.5.4 Electrical Insulation for Electrical Cables and Connections

The insulated cables and connections commodities are separated for aging management review into subcategories based on their treatment in NUREG-2191:

- Electrical Insulation for Electrical Cables and Connections
 - Electrical penetration pigtails
 - Splices
 - Insulating Portions of Terminal Blocks
- Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
- Electrical Conductor Insulation for Inaccessible Instrumentation and Control Cables
- Electrical Conductor Insulation for Inaccessible Low Voltage Power Cables
- Electrical Conductor Insulation for Inaccessible Medium Voltage Power Cables

Insulated cables and connections that are passive and 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.

Insulated cables and connections inside the enclosure of an active device (e.g., motor leads and connections, cables and connections internal to relays, chargers, switchgear, transformers, power supplies) are maintained along with the other subcomponents inside the enclosure and are not subject to an aging management review.

2.5.2.5.5 Metal Enclosed Bus

The Metal Enclosed Buses (MEBs) in scope at NMP1 are the following:

- 24KV AC isolated phase bus duct from the main generator to the 22.8KV – 345KV AC main step-up transformers T01 and T02, and to the 24KV – 4.16KV AC transformer T10.
- 4.16KV AC non-segregated bus duct from the 24KV – 4.16KV AC transformer T10 to power boards 11 and 12.

- 4.16KV AC non-segregated bus duct from the Reserve Transformer 101N to power boards 101, 11, and circuit breaker R1012/151. This circuit breaker supplies power board 102 using cable.
- 4.16KV AC non-segregated bus duct from the Reserve Transformer 101S to power boards 101, 12, and circuit breaker R1013/161. This circuit breaker supplies power board 103 using cable.

The metal enclosed bus commodity group includes current-carrying metallic bus bars that are enclosed within a protective metallic duct or housing. Metal enclosed bus construction also includes bus insulation and insulators from structural supports. Some metal enclosed bus at NMP1 is not part of an active component, not included in the EQ program, and provides power to circuits that are within the scope of SLR. Therefore, these metal enclosed bus commodities meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

2.5.2.5.6 Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors

The switchyard bus and connections, transmission conductor and transmission connections components are contained in switchyard circuits used to supply power from the electric utility transmission system to plant buses. These circuits provide power to in scope license renewal components credited for recovery from a station blackout and credited for fire protection during non-power operations. The switchyard bus and connections, transmission conductor and transmission connections are passive and are not included in the EQ program. Therefore, the switchyard bus and connections, transmission conductor and transmission connections commodity group meets the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

Table 2.5.2-1 Electrical Commodities Subject to Aging Management Review

Commodity	Intended Function
Cable Connections (metallic parts)	Electrical Continuity
Electrical Insulation for Electrical Cables and Connections	Insulate (Electrical)
High-Voltage Electrical Insulators	Insulate (Electrical)
Metal Enclosed Bus	Electrical Continuity
	Insulate (Electrical)
	Shelter, Protection
Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors	Electrical Continuity

The aging management review results for these commodities are provided in:

Table 3.6.2-1 Electrical Commodities
Summary of Aging Management Evaluation.

3.0 AGING MANAGEMENT REVIEW RESULTS

This section provides the results of the aging management review for those structures and components identified in Section 2.0 as being subject to aging management review.

Descriptions of the service environments that were used in the aging management review to determine aging effects requiring management are included in Table 3.0-1, Nine Mile Point Nuclear Station, Unit 1 (NMP1) Service Environments. The environments used in the aging management reviews are listed in the NMP1 Aging Management Review (AMR) Environment column. The third column identifies one or more of the NUREG-2191 environments that were used when comparing the NMP1 Aging Management Review results to the NUREG-2191 results.

Most of the 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-2192, 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-2192, 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 Pressure Vessel, within the Reactor Vessel, Internals, and Reactor Coolant System subsection, this table would be 3.1.2-3 and for the Reactor Pressure Vessel Internals, it would be table 3.1.2-5. 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

NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," contains the generic evaluation of existing plant programs. It documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the subsequent extended period of operation. The evaluation results documented in NUREG-2191 indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components, within the scope of license renewal, without change. NUREG-2191 also contains recommendations on specific areas for which existing programs should be enhanced for license renewal. In order to take full advantage of NUREG-2191, a comparison between the NMP1 AMR results and the tables of NUREG-2191 has been performed. The Table 2s provide the results of these comparisons for each of the NMP1 systems, structures, and commodity groups. The Table 1s provide a summary for each of the NUREG-2192 subsections, including reference to the discussion of any applicable further evaluations.

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 first three columns, “New, Modified, Deleted, Edited Item,” “ID,” and “Type,” 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:

- When “Further Evaluation Recommended” is “Yes,” 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-2192 assumptions, if applicable
- A discussion of how the line is consistent with the corresponding line item in NUREG-2192, when that may not be intuitively obvious
- A discussion of how the item is different than the corresponding line item in NUREG-2192 when it may appear to be consistent (e.g., when there is exception taken to an aging management program that is listed in NUREG-2192), 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, for NMP1, the Engineered Safety Features System Group contains tables specific to the Containment Spray System, Core Spray System, and Emergency Cooling System.

Table 2 consists of the following ten columns:

- AMR ID
- Component Type
- Intended Function
- Material
- Environment

- Aging Effect Requiring Management
- Aging Management Programs
- NUREG-2191 Item
- NUREG-2192 Table 1 Item
- Notes

AMR ID – The first column contains a numeric ID to individually designate lines in the Table. The AMR ID is unique to the corresponding line within the application.

Component Type – The second 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 third column contains the license renewal intended functions for the listed component types. Definitions of intended functions are contained in Table 2.1-1.

Material – The fourth column lists the particular materials of construction for the component type.

Environment – The fifth column lists the environments to which the component types are exposed. Service environments are indicated and a list of these environments is provided in Table 3.0-1.

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 sixth column.

Aging Management Programs – The aging management programs used to manage the aging effects requiring management are listed in the seventh 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 eighth column of Table 2. If there is no corresponding item number in NUREG-2191, this field in column eight is left blank. Thus, a reviewer can readily identify the correlation between the plant-specific tables and the NUREG-2191 tables.

NUREG-2192 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 ninth column of Table 2. If there is no corresponding item in NUREG-2191, this field

in column nine is left blank. The NUREG-2192 Table 1 Item allows correlation of the information from the two tables.

Notes – The notes provided in each Table 2 describe how the information in the table aligns with the information in NUREG-2191. Each Table 2 contains standard lettered notes and, if applicable, plant-specific numbered notes.

The standard lettered notes (e.g., A, B, C) provide standard information regarding comparison of the NMP1 aging management review results with the NUREG-2191 Aging Management Table line item identified in the eighth column. In addition to the standard lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

TABLE USAGE

Table 1

The reviewer evaluates each 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 the most 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 NMP1 evaluations and programs align with NUREG-2192. 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.

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. 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 eight, NUREG-2191 Item. The reviewer can refer to the item number in NUREG-2191, if desired, to verify the correlation. If the column is blank, 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 NUREG-2192 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 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.

A listing of the acronyms used in this section is provided in Section 1.6.

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 60 years of plant operation. 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 has been identified. See SLRA Section 4.3 for details regarding the NMP1 fatigue design bases, fatigue TLAAs identified, and TLAA evaluations for the subsequent period of extended operation.

Table 3.0-1 – Nine Mile Point Nuclear Station, Unit 1 Service Environments

NMP1 AMR Environment	Description	NUREG-2191 Environments Used for AMR Comparison
10 CFR 50.49 EQ Environment	This environment is used for 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, in which the requirements of 10 CFR 50.49 (EQ) would be applicable.	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	The adverse localized environment represents conditions with excessive heat, radiation, or moisture, sometimes in the presence of oxygen. The effect can be concentrated or applicable to a general plant area.	Adverse localized environment caused by heat, radiation, or moisture
Adverse Localized Environment Caused by Significant Moisture	This environment is the same as the adverse localized environment, except that it is caused by the presence of significant moisture.	Adverse localized environment caused by significant moisture
Air – Dry	The air – dry environment is used for air that has been treated to reduce its dew point well below the system operating temperature and treated to control lubricant content, particulate matter, and other corrosive contaminants. Use of this term is only associated with internal air environments located in the CO ₂ system or downstream of the compressed air system air dryers.	Air Air-dry
Air – Indoor, Controlled	The air – indoor, controlled environment is one in which the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment. For electrical components and structures, the controlled environment must be sufficient to show that the electrical component(s) or structure(s) are not subjected to the cited aging effect(s) (e.g., reduced insulation resistance). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in scope components exists when citing the air-indoor controlled environment.	Air Air-indoor controlled

NMP1 AMR Environment	Description	NUREG-2191 Environments Used for AMR Comparison
Air – Indoor, Uncontrolled	The air – indoor, uncontrolled environment is for indoor locations that are sheltered/protected from weather. Air temperatures and surface temperatures of components in this environment are higher than the dew point (i.e., condensation can occur, but only rarely). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in-scope components exists when citing the air – indoor, uncontrolled environment. The air – indoor, controlled environments in NUREG-2191 may also be conservatively included within this uncontrolled environment.	Air Air–indoor uncontrolled System temperature up to 288°C (550°F)
Air – Outdoor	The air – outdoor environment includes atmospheric air exposed to weather and ambient temperatures and humidity (with a relative humidity up to 100%). This environment may be subject to pollutants, periodic wetting, and wind.	Air Air–outdoor
Closed Cycle Cooling Water	Closed cycle cooling water includes treated water subject to the Closed Treated Water Systems program, which is Aging Management Program XI.M21A in NUREG-2191. The Closed Treated Water Systems program relies on maintenance of system corrosion inhibitor concentrations within specified limits of EPRI 3002000590 (EPRI 2013-TN9378) to minimize corrosion. Demineralized water is treated with corrosion inhibitors, pH control agents, or biocides, as needed.	Closed-cycle cooling water
Closed Cycle Cooling Water >140°F	The closed cycle cooling water >140°F environment is the same as the closed cycle cooling water environment, except the closed cycle cooling water >140°F environment is to be selected for components with an operating temperature >140°F that are constructed of stainless steel or copper alloy with 15% zinc or more.	Closed-cycle cooling water Closed-cycle cooling water >60°C (>140°F)
Concrete	The concrete environment is one where components are embedded in concrete. This environment is considered aggressive if the concrete pH is <5.5, or chloride concentration is >500 ppm, or sulfate concentration is >1,500 ppm.	Concrete

NMP1 AMR Environment	Description	NUREG-2191 Environments Used for AMR Comparison
Condensation	The condensation environment is an air environment containing warm or moist air where condensation may occur and periodically wet the component surface. This environment includes air or gas with enough moisture to facilitate loss of material caused by general, pitting, and crevice corrosion for most common materials. It also facilitates cracking in those materials susceptible to stress corrosion cracking due to the potential for internal or external surface contamination. Although condensation may occur, it is not expected to be significant enough to result in ponding and pooling that can pose a spatial interaction concern. Ponding and pooling to this degree, as would be expected to be found in HVAC drip pans and drains lines, is considered Waste Water. The condensation air environment is used for air drawn inside ventilation systems and air spaces within tanks. Certain individual components reside inside larger components such that their external surfaces are exposed to the internal environment of the larger component (e.g., tubes in air coolers). For these situations, condensation is designated as the external environment. The condensation environment is also used for certain insulated components. Because of air in-leakage through minor gaps in insulation, condensation can occur underneath the insulation on components when the operating temperature of the component is below the dew point of the air on the external surfaces of the insulation.	Condensation
Diesel Exhaust	The diesel exhaust environment represents the exhaust from diesel engines. It is considered to have the potential to concentrate contaminants and be subject to wetting through condensation.	Diesel exhaust
Fuel Oil	The fuel oil environment includes fuel oil for the emergency diesel generators, diesel-driven fire pumps, etc. Water contamination of fuel oil is assumed.	Fuel oil
Gas	The gas environment includes inert or nonreactive gases where aging effects are not expected to degrade the ability of the structure or component to perform its intended function for the subsequent period of extended operation.	Gas

NMP1 AMR Environment	Description	NUREG-2191 Environments Used for AMR Comparison
Groundwater/Soil	The groundwater/soil environment is the external environment for structural components buried in the soil where there is groundwater in the soil. This environment is considered aggressive if the acidic solution pH is <5.5, or chloride concentration is >500 ppm, or sulfate concentration is >1,500 ppm.	Ground water/soil Soil
Lubricating Oil	Lubricating oils are low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication. Water contamination of lubricating oil is assumed. Hydraulic fluids are also included within this environment for purposes of aging management review.	Lubricating oil
Lubricating Oil (Waste Oil)	Lubricating oil (waste oil) is oil that has been collected as it leaks from a component (e.g., reactor coolant pumps) and as such, contains potential contaminants such as water and dirt.	Lubricating oil (waste oil)
Raw Water	Lake Ontario provides the sources of raw water utilized by NMP1. Raw water is also rain or ground water. Raw water is water that has not been demineralized or treated to any significant extent. This can include water for use in open-cycle cooling water and fire protection systems. Potable water, water that is used for drinking or other personal use, is considered raw water. Raw water in plant systems may have been rough filtered to remove large particles and may contain a biocide additive for control of micro- and macro-organisms.	Raw water Raw water (potable) Waste water
Raw Water >140°F	The raw water >140°F environment is the same as the raw water environment, except the raw water >140°F environment is used for components with an operating temperature >140°F that are constructed of stainless steel.	Raw water
Reactor Coolant	The reactor coolant environment is treated water in the reactor coolant system and connected systems at or near full operating temperature. The reactor coolant environment also includes steam within the vessel. The temperature of the reactor coolant environment is always assumed to be >482 °F. The reactor coolant environment has been selected for the following systems for consistency with the NUREG-2191 terminology: Reactor Pressure Vessel, Reactor Pressure Vessel Internals, Reactor Coolant Pressure Boundary System, and Reactor Recirculation System.	Reactor coolant Reactor coolant >250°C (>482°F) Reactor coolant >250°C (>482°F) and neutron flux Reactor coolant and neutron flux Treated water

NMP1 AMR Environment	Description	NUREG-2191 Environments Used for AMR Comparison
Reactor Coolant and Neutron Flux	The reactor coolant and neutron flux environment is used for components within the Reactor Pressure Vessel System and Reactor Pressure Vessel Internals System that are in contact with reactor coolant and are exposed to neutron fluence projected to exceed 1.0×10^{17} n/cm ² (E >0.1 MeV) within 80 years. The temperature of the reactor coolant and neutron flux environment is always assumed to be >482°F.	Reactor coolant Reactor coolant >250°C (>482°F) and neutron flux Reactor coolant and neutron flux
Sodium Pentaborate Solution	The sodium pentaborate solution environment is associated with sodium pentaborate, used in the Standby Liquid Control System.	Sodium pentaborate solution
Soil	The soil environment is the external environment for mechanical components buried in the soil, and it includes ground water in the soil. This environment is considered aggressive if the acidic solution pH is <5.5, or chloride solution is >500 ppm, or sulfate concentration is >1,500 ppm.	Buried Soil
Steam	The steam environment is the internal environment associated with dry steam, such as main steam up to the high pressure turbine. The Water Chemistry program is used for managing aging effects in dry steam environments, but the One-Time Inspection program is not required by NUREG-2191. Wet steam environments for NMP1 are typically described as either treated water or reactor coolant, depending upon location, but may use the NUREG-2191 steam environment for cumulative fatigue damage or loss of material aging effects.	Reactor coolant Steam Treated water
Treated Water	Treated water is demineralized water or chemically purified water and is the base water for all clean systems. Depending on the system, treated water may require further processing. Treated water may be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. The treated water environment also includes wet steam. Dry steam, such as main steam up to the high pressure turbine, is addressed as its own environment.	Reactor coolant Steam Treated water

NMP1 AMR Environment	Description	NUREG-2191 Environments Used for AMR Comparison
Treated Water >140°F	The treated water >140°F environment is the same as the treated water environment, except the treated water >140°F environment is to be selected for components with an operating temperature >140°F that are constructed of stainless steel or nickel alloy. For materials other than stainless steel or nickel alloy, the treated water environment is used. The treated water >140°F environment includes wet steam. Dry steam, such as main steam up to the high pressure turbine, is addressed as its own environment.	Reactor coolant Steam Treated water Treated water >60°C (>140°F)
Treated Water >200°F	The treated water >200°F environment is the same as the treated water environment, except the treated water >200°F environment is to be selected for Reactor Water Cleanup (RWCU) System, piping and piping components outboard of the second containment isolation valves with a diameter ≥4 inches nominal pipe size and for RCPB Class 1 piping, piping components greater than or equal to 4 NPS.	Steam Treated water Treated water >93°C (>200°F)
Treated Water >482°F	The treated water >482°F environment is the same as the treated water environment, except the treated water >482°F environment is to be selected for components with an operating temperature >482°F that are constructed of cast austenitic stainless steel (CASS). The treated water >482°F environment includes wet steam. Dry steam, such as main steam up to the high pressure turbine, is addressed as its own environment.	Reactor coolant >250°C (>482°F) Steam Treated water Treated water >60°C (>140°F)
Underground	The underground environment is applicable to mechanical components contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is limited.	Underground
Waste Water	Waste water includes radioactive, potentially radioactive, or nonradioactive waters that are collected from equipment and floor drains, vent system drains, and waters processed by the radwaste system. Waste water may contain contaminants, including oil, depending on location, as well as treated water that is not monitored by a chemistry program. Collected water in HVAC drip pans and HVAC drain lines is considered to be waste water.	Raw water Waste water

NMP1 AMR Environment	Description	NUREG-2191 Environments Used for AMR Comparison
Waste Water >140°F	The waste water >140°F environment is the same as the waste water environment, except the waste water >140°F environment is to be selected for systems operating at temperatures >140°F that contain stainless steel components.	Waste water
Water – Flowing	The water – flowing environment is water that is refreshed, thus having larger impact on leaching; this can be rainwater, raw water, groundwater, groundwater intrusion, or flowing water under a foundation.	Water–flowing

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.

- Control Rod Drive System (2.3.1.1)
- Reactor Coolant Pressure Boundary System (2.3.1.2)
- Reactor Pressure Vessel (2.3.1.3)
- Reactor Pressure Vessel Instrumentation System (2.3.1.4)
- Reactor Pressure Vessel Internals (2.3.1.5)
- Reactor Recirculation System (2.3.1.6)

3.1.2 RESULTS

The following tables summarize the results of the aging management review for Reactor Vessel, Internals, and Reactor Coolant System.

Table 3.1.2-1 Control Rod Drive System - Summary of Aging Management Evaluation

Table 3.1.2-2 Reactor Coolant Pressure Boundary System - Summary of Aging Management Evaluation

Table 3.1.2-3 Reactor Pressure Vessel - Summary of Aging Management Evaluation

Table 3.1.2-4 Reactor Pressure Vessel Instrumentation System - Summary of Aging Management Evaluation

Table 3.1.2-5 Reactor Pressure Vessel Internals - Summary of Aging Management Evaluation

Table 3.1.2-6 Reactor Recirculation System - Summary of Aging Management Evaluation

3.1.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.1.2.1.1 Control Rod Drive System

Materials

The materials of construction for the Control Rod Drive System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel

- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The Control Rod Drive System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Condensation
- Lubricating Oil
- Treated Water
- Treated Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Control Rod Drive System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Control Rod Drive System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.1.2.1.2 Reactor Coolant Pressure Boundary System

Materials

The materials of construction for the Reactor Coolant Pressure Boundary System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Austenitic Stainless Steel (CASS)
- Stainless Steel
- Stainless Steel Bolting

Environments

The Reactor Coolant Pressure Boundary System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Reactor Coolant
- Steam
- Treated Water
- Treated Water > 140°F
- Treated Water > 200°F

Aging Effect Requiring Management

The following aging effects associated with the Reactor Coolant Pressure Boundary System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Fracture Toughness
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Coolant Pressure Boundary System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.22)

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- BWR Stress Corrosion Cracking (B.2.1.5)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- One-Time Inspection (B.2.1.20)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)
- TLAA
- Water Chemistry (B.2.1.2)

3.1.2.1.3 Reactor Pressure Vessel

Materials

The materials of construction for the Reactor Pressure Vessel components are:

- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Carbon Steel
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Nickel Alloy
- Stainless Steel

Environments

The Reactor Pressure Vessel components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Reactor Coolant
- Reactor Coolant and Neutron Flux

Aging Effect Requiring Management

The following aging effects associated with the Reactor Pressure Vessel components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- 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 Pressure Vessel components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- BWR Penetrations (B.2.1.6)
- BWR Stress Corrosion Cracking (B.2.1.5)
- BWR Vessel ID Attachment Welds (B.2.1.4)
- BWR Vessel Internals (B.2.1.7)
- Neutron Fluence Monitoring (B.3.1.2)
- One-Time Inspection (B.2.1.20)
- Reactor Head Closure Stud Bolting (B.2.1.3)
- Reactor Vessel Material Surveillance (B.2.1.19)
- TLAA
- Water Chemistry (B.2.1.2)

3.1.2.1.4 Reactor Pressure Vessel Instrumentation System

Materials

The materials of construction for the Reactor Pressure Vessel Instrumentation System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Stainless Steel

Environments

The Reactor Pressure Vessel Instrumentation System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Treated Water
- Treated Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Reactor Pressure Vessel Instrumentation System components 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 Reactor Pressure Vessel Instrumentation System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- One-Time Inspection (B.2.1.20)
- Water Chemistry (B.2.1.2)

3.1.2.1.5 Reactor Pressure Vessel Internals

Materials

The materials of construction for the Reactor Pressure Vessel Internals components are:

- Cast Austenitic Stainless Steel (CASS)
- Nickel Alloy
- Stainless Steel

Environments

The Reactor Pressure Vessel Internals components are exposed to the following environments:

- Gas
- Reactor Coolant
- Reactor Coolant and Neutron Flux

Aging Effect Requiring Management

The following aging effects associated with the Reactor Pressure Vessel Internals components require management:

- 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 Pressure Vessel Internals components:

- BWR Vessel Internals (B.2.1.7)
- TLAA
- Water Chemistry (B.2.1.2)

3.1.2.1.6 Reactor Recirculation System

Materials

The materials of construction for the Reactor Recirculation System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with less than 15% Zinc
- Stainless Steel

Environments

The Reactor Recirculation System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Closed Cycle Cooling Water > 140°F
- Lubricating Oil
- Reactor Coolant
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Reactor Recirculation System components 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 Reactor Recirculation System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- TLAA
- Water Chemistry (B.2.1.2)

3.1.2.2 **AMR Results for Which Further Evaluation is Recommended by the GALL Report**

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Reactor Vessel, Internals, and Reactor Coolant System, those programs are addressed in the following subsections.

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 applicable to Nine Mile Point Nuclear Station, Unit 1 (NMP1) have been evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of metal fatigue as a TLAA for the Reactor Vessel, Reactor Vessel Internals, and Reactor Coolant Pressure Boundary systems is discussed in Section 4.3.

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 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) License Renewal and Standardization Branch (RLSB-1) (Appendix A.1 of this SRP-SLR).*

Table 3.1.1 Item Number 3.1.1-012: This item is applicable to PWRs only and therefore is not used for NMP1.

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.

Table 3.1.1 Item Number 3.1.1-012: This item is applicable to PWRs only and therefore is not used for NMP1.

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} neutrons per square centimeter [N/cm^2] ($E > 1$ mega electron-volt [MeV]) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAAs as defined in 10 CFR 54.3 (TN4878). The TLAAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The TLAA which covers aspects of neutron irradiation embrittlement is addressed separately in Section 4.2, "Reactor Pressure Vessel Neutron Embrittlement Analysis," of this SRP-SLR.*

Table 3.1.1, Item Number 3.1.1-013: This item addresses loss of fracture toughness due to neutron irradiation embrittlement in 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. The NMP1 reactor vessel beltline shell, nozzle, and weld components are carbon or low alloy steel with stainless steel cladding. Neutron irradiation embrittlement for all ferritic reactor vessel shell components and welds that have a projected neutron fluence value greater than 1×10^{17} n/cm² (E>1 MeV) at the end of the subsequent license renewal term is evaluated as a TLAA as discussed in Section 4.2.

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 RV 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 (TN249), 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 time-dependent inputs for the plant's RV 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."

Table 3.1.1 Item Number 3.1.1-014: This item addresses loss of fracture toughness due to neutron irradiation embrittlement in 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. The Reactor Vessel Material Surveillance (B.2.1.19) program in conjunction with the Neutron Fluence Monitoring (B.3.1.2) program will be implemented to manage loss of fracture toughness due to neutron irradiation embrittlement of the carbon or low alloy steel with stainless steel cladding reactor vessel beltline components and welds exposed to a reactor coolant and neutron flux environment. The Reactor Vessel Material Surveillance (B.2.1.19) program meets the requirements of 10 CFR 50, Appendix H. The NMP1 Reactor Vessel Material Surveillance (B.2.1.19) program will rely on the BWRVIP ISP host site (Peach Bottom Unit 3) to withdraw representative surveillance capsules during the subsequent period of extended operation per the approved schedule of BWRVIP-321, Revision 1-A, with a neutron fluence between one and two times the

projected peak vessel neutron fluence that would be found at the end of the subsequent period of extended operation. Specific specimens representing NMP1 materials will then be tested. The Neutron Fluence Monitoring (B.3.1.2) program will be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the time-limited aging analyses (TLAAs) that evaluate loss of fracture toughness due to neutron irradiation embrittlement of the reactor vessel.

3. *Reduction in Fracture Toughness is a plant-specific TLA 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.*

Table 3.1.1 Item Number 3.1.1-015: This item is applicable to PWRs only and therefore is not used for NMP1.

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 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 effects involving cracking of SS and nickel-alloy RV flange leak detection lines are not applicable and do not require management if: (i) the plant-specific OE does not reveal a history of SCC or IGSCC and (ii) a one-time inspection demonstrates that the effect of aging is not evident. 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.*

Table 3.1.1 Item Number 3.1.1-016: This item evaluates cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) in stainless steel and nickel alloy reactor vessel flange leak detection lines exposed to air-indoor uncontrolled environments. The reactor vessel flange leak detection lines are stainless steel. Plant-specific operating experience (OE) associated with stainless steel piping and piping components, including the reactor vessel flange leak detection lines, has been evaluated to determine if cracking due to SCC or IGSCC has occurred. Cracking due to SCC or IGSCC has not been identified as an aging effect at NMP1 for stainless steel piping and piping components including the reactor vessel flange leak detection lines exposed to air-indoor uncontrolled environments. Accordingly, the One-Time Inspection (B.2.1.20) program will be implemented to demonstrate that the aging effect of cracking is not occurring in stainless steel reactor vessel flange leak detection lines. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

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).*

Table 3.1.1 Item Number 3.1.1-017: This item evaluates cracking due to SCC and IGSCC in stainless steel isolation condenser components exposed to reactor coolant environments. NMP1 relies on supplemental testing and inspection activities to detect cracking due to SCC, IGSCC, and cyclic loading of stainless steel emergency condenser components exposed to reactor coolant. The stainless steel emergency condenser components at NMP1 include the tubes and tubesheets. Supplemental activities for the emergency condensers consist of temperature and radioactivity monitoring of the shell side (cooling) water to identify potential tube leakage due to cracking, visual tube inspections, and online tube leakage tests.

Temperature monitoring of the emergency condensers is conducted continuously through installed instrumentation with local indications and alarms in the control room. Emergency cooling system temperature data is trended twice per year. The temperature monitoring procedure contains separate acceptance criteria for the steam inlet piping, emergency condenser shell water, and condensate return piping. The acceptance criteria are based upon design analyses to prevent damage to the piping and condensers. The emergency condenser vent is monitored continuously in the control room for radioactivity. Additionally, the emergency condenser shell side water is sampled monthly for radioactivity. Temperature and radioactivity monitoring of the emergency condenser shell side (cooling) water will be implemented through the Water Chemistry (B.2.1.2) program.

Visual inspections are performed for the accessible outer surfaces of the peripheral tubes and the accessible surfaces of the shell side of the tubesheets to identify potential cracking and loss of material. The NMP1 Emergency Condenser design features end bells that are welded to the heat exchanger shell, therefore eddy current testing of the emergency condenser tubes is not practical. For additional verification that the emergency condenser tubes are not leaking, NMP1 performs online tube leakage tests. These tests isolate makeup water to the shell side of the emergency condenser loop being tested and monitor the shell side water level. A water level rise in the shell side during this test would indicate tube leakage. These supplemental activities verify that significant degradation is not occurring, and therefore the intended function of the emergency condensers will be maintained during the subsequent period of extended operation. Visual inspections and tube leakage tests of the emergency condenser tubes and tubesheets will be implemented through the ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD (B.2.1.1) program for subsequent license renewal.

Existing station procedures include acceptance criteria for the supplemental testing and inspection activities to ensure that appropriate corrective actions are taken if

direct (i.e., visual inspection results) or indirect (i.e., increased shell side temperature or radioactivity) evidence of degradation is identified.

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. The CLBs that include these types of evaluations may need to be identified as TLAAAs if they are determined to conform to the six criteria for defining TLAAAs in 10 CFR 54.3(a) (TN4878). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code Section XI¹. See SRP-SLR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

Table 3.1.1 Item Number 3.1.1-018: This item is applicable to PWRs only and therefore is not used for NMP1.

3.1.2.2.6 Cracking Due to Stress Corrosion Cracking

1. *Deleted.*
2. *Deleted.*
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 involving cracking in SS and nickel-alloy RV flange leak detection lines is not applicable and does not require management if: (i) the plant-specific OE does not reveal a history of SCC and (ii) a one-time inspection demonstrates that effect of aging is not evident. 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.*

Table 3.1.1 Item Number 3.1.1-139: This item is applicable to PWRs only and therefore is not used for NMP1.

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

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

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).

Table 3.1.1 Item Number 3.1.1-021: This item evaluates cracking due to cyclic loading in steel and stainless steel isolation condenser components exposed to reactor coolant environments. NMP1 relies on supplemental testing and inspection activities to detect cracking due to SCC, IGSCC, and cyclic loading of stainless steel emergency condenser components exposed to reactor coolant. The stainless steel emergency condenser components at NMP1 include the tubes and tubesheets. Supplemental activities for the emergency condensers consist of temperature and radioactivity monitoring of the shell side (cooling) water to identify potential tube leakage due to cracking, visual tube inspections, and online tube leakage tests.

Temperature monitoring of the emergency condensers is conducted continuously through installed instrumentation with local indications and alarms in the control room. Emergency cooling system temperature data is trended twice per year. The temperature monitoring procedure contains separate acceptance criteria for the steam inlet piping, emergency condenser shell water, and condensate return piping. The acceptance criteria are based upon design analyses to prevent damage to the piping and condensers. The emergency condenser vent is monitored continuously in the control room for radioactivity. Additionally, the emergency condenser shell side water is sampled monthly for radioactivity. Temperature and radioactivity monitoring of the emergency condenser shell side (cooling) water will be implemented through the Water Chemistry (B.2.1.2) program.

Visual inspections are performed for the accessible outer surfaces of the peripheral tubes and the accessible surfaces of the shell side of the tubesheets to identify potential cracking and loss of material. The NMP1 Emergency Condenser design features end bells that are welded to the heat exchanger shell, therefore eddy current testing of the emergency condenser tubes is not practical. For additional verification that the emergency condenser tubes are not leaking, NMP1 performs online tube leakage tests. These tests isolate makeup water to the shell side of the emergency condenser loop being tested and monitor the shell side water level. A water level rise in the shell side during this test would indicate tube leakage. These supplemental activities verify that significant degradation is not occurring, and therefore that the intended function of the emergency condensers will be maintained during the subsequent period of extended operation. Visual inspections and tube leakage tests of the emergency condenser tubes and tubesheets will be implemented through the ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD (B.2.1.1) program for subsequent license renewal.

Existing station procedures include acceptance criteria for the supplemental testing and inspection activities to ensure that appropriate corrective actions are taken if direct (i.e., visual inspection results) or indirect (i.e., increased shell side temperature or radioactivity) evidence of degradation is identified.

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 of a plant-specific AMP is recommended to ensure that this aging effect is adequately

managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.1.1 Item Number 3.1.1-022: This item is applicable to PWRs only and therefore is not used for NMP1.

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)” (ML12017A191 through ML12017A197 and ML12017A199), provided the industry’s initial set of aging management inspection and evaluation (I&E) recommendations for the RVI components that are included in the design of a PWR facility. Since the issuance of MRP-227-A on January 9, 2012, EPRI updated its I&E guidelines for the PWR RVI components in TR No. 3002017168, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)” (ML20175A112). MRP-227, Revision 1-A, incorporated the industry’s bases for resolving operating experience and industry lessons learned resulting from component-specific inspections performed since the issuance of MRP-227-A in January 2012. The staff found the guidelines in MRP-227, Revision 1-A acceptable, as documented in a staff-issued safety evaluation dated April 25, 2019 (ML19081A001) and approved the TR for use as documented in the staff’s letters to the EPRI Materials Reliability Program (MRP) dated February 19, 2020 and July 7, 2020 (ML20006D152 and ML20175A149).

In MRP-227, Revision 1-A, the EPRI MRP identified that the following aging mechanisms may be applicable to the design of the RVI components in these types of facilities: (i) SCC, (ii) irradiation-assisted stress corrosion cracking (IASCC), (iii) fatigue, (iv) wear, (v) neutron irradiation embrittlement, (vi) thermal aging embrittlement, (vii) void swelling and irradiation growth or component distortion, and (viii) thermal or irradiation-enhanced stress relaxation or irradiation-enhanced creep.

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 the applicable inspection categories (as evaluated in MRP-227, Revision 1-A) were 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’s assessment in MRP-227, Revision 1-A, did not evaluate the potential impacts of operation of Westinghouse-designed, B&W designed and CE designed reactors during an SLR operating period (60 to 80 years) on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227, Revision 1-A or the applicable MRP background documents (e.g., MRP-191, Revision 1, for Westinghouse-designed or CE designed RVI components or MRP-189, Revision 2, for B&W designed components). As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227, Revision 1-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, Revision 1-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 changes to the MRP-227, Revision 1-A based program that are necessary to provide reasonable assurance that the effects of age-related degradation will be managed during the subsequent period of extended operation. The criteria for the gap analysis are described in GALL-SLR Report AMP XI.M16A. If a gap analysis is needed to establish the appropriate aging management criteria for the RVI components, the applicant has the option of including the gap analysis in the SLRA or making the gap analysis and any supporting gap analysis documents available in the in-office audit portal for the SLRA review.

The SLR applicants for units of a PWR design will no longer need to include separate SLRA Appendix C Section responses in resolution of the Applicant/Licensee Action Item (A/LAIs) previously issued on MRP-227-A because the A/LAIs were resolved and closed by the staff in the April 25, 2019, safety evaluation for MRP-227, Revision 1-A. The sole A/LAI issued by the staff in the safety evaluation dated April 25, 2019, relates to an applicant's methods and timing of inspections that will be applied to the baffle to former bolts or core shroud bolts in the plant design. Since an applicant's resolution of this A/LAI can be appropriately addressed in the "Operating Experience" program element discussion for the AMP and in the applicant's basis document for the AMP, a separate SLRA Appendix C response for the A/LAI is not necessary.

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) (TN4878) 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. If the AMP is a plant-specific program, 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 this SRP-SLR.

Table 3.1.1 Item Numbers 3.1.1-028, 3.1.1-051a, 3.1.1-051b, 3.1.1-052a, 3.1.1-052b, 3.1.1-052c, 3.1.1-053a, 3.1.1-053b, 3.1.1-053c, 3.1.1-055a, 3.1.1-055b, 3.1.1-055c, 3.1.1-056a, 3.1.1-056b, 3.1.1-056c, 3.1.1-058a, 3.1.1-058b, 3.1.1-059a, 3.1.1-059b, 3.1.1-059c, 3.1.1-118, 3.1.1-119: These items are applicable to PWRs only and therefore are not used for NMP1.

3.1.2.2.10 Loss of Material Due to Wear

1. *Industrial 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 Dominion 2007-TN8058). The CRD head penetration nozzles are also called control rod drive mechanism nozzles or control rod drive mechanism 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 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 CLB.*

Table 3.1.1 Item Number 3.1.1-116: This item is applicable to PWRs only and therefore is not used for NMP1.

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 interaction of the thermal sleeve with the adjacent components (such as CRD head penetration nozzle, drive rod, and penetration housing). For example, loss of material can occur where the thermal sleeve exits from the head penetration nozzle inside the RV (Southern Co. 2007-TN8059, PWROG 2018-TN8067). This type of wear is called thermal sleeve outer diameter wear, which results from the interactions between the thermal sleeve outer surface and the head penetration nozzle. Loss of material can also occur near the bottom of the thermal sleeve due to the interactions between the thermal sleeve inner surface and the drive rod passing through the thermal sleeve (PWROG 2018-TN8067). This type of wear is called thermal sleeve inner-diameter wear. In addition, thermal sleeve flange wear can occur due to the interactions between the bottom side of the thermal sleeve flange and the CRD penetration housing near the top of the thermal sleeve PWROG 2018-TN8067, NRC 2018-TN8048, EPRI 2018-TN8068). 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.*

Table 3.1.1 Item Number 3.1.1-117: This item is applicable to PWRs only and therefore is not used for NMP1.

3. *Industry OE indicates that significant loss of material due to wear can occur in ASME Code Class 1, small-bore piping. For example, loss of material can occur in the presence of reflective metal insulation (RMI) and flow-induced vibrations of ASME Code Class 1 small-bore piping. This type of wear is difficult to identify unless the insulation is removed and the outside diameter (OD) of the piping is visually examined for wear marks (NRC IN 2007-21 TN8069, NRC 2007-21 Supp.1 TN8034). This type of wear, defined as OD pipe wear, can potentially occur nearly 360° around the OD of the subject pipe and could significantly reduce the load-bearing capacity of the subject pipe. Therefore, the applicant should perform a further evaluation to confirm the absence of the specific aging effect. If it is determined that the insulation has the potential to cause wear, the licensee may choose to mitigate the loss of material due to wear or alternatively use an existing program for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. The reviewer should ensure that the applicant has verified through inspections that OD pipe wear is not an applicable aging effect that needs to be monitored or provide for a periodic inspection program so that significant OD wear of ASME Code Class 1 small-bore piping is detected prior to the loss of intended function.*

Table 3.1.1 Item Number 3.1.1-141: This item addresses loss of material due to wear in steel, stainless steel, or nickel alloy ASME Code Class 1 small-bore piping in air due to the presence of reflective metal insulation and flow induced vibration. Plant-specific OE from 2016 to 2026 was reviewed to determine if the presence of reflective metal insulation and flow induced vibration has resulted in outer diameter pipe wear for ASME Code Class 1 small-bore piping. The review did not identify any

instances of wear (or leakage due to wear) attributable to the presence of reflective metal insulation. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to wear is not occurring in steel, stainless steel, or nickel alloy ASME Code Class 1 small-bore piping in the presence of reflective metal insulation and flow induced vibration. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

3.1.2.2.11 Cracking Due to Primary Water Stress Corrosion Cracking

1. *Foreign OE in SGs with a design similar to that of Westinghouse SGs (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in 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 (in.) (EPRI 2014-TN8060).*

All but one of these instances of cracking has been detected in divider plate assemblies that are approximately 1.3 in. in thickness. For the cracks in the 1.3-in. 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 in., the cracking occurred in a divider plate assembly with a thickness of approximately 2.4 in. 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-in. deep.

Although these instances indicate that the Water Chemistry AMP 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 (DBAs)). In addition, the industry analyses indicate that flaws in the divider plate assembly should 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 DBAs), 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, use of the One-Time Inspection 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 2014-TN8060) are applicable and bounding for the unit, use of the One-Time Inspection AMP is not necessary. Applicants may demonstrate that the industry analyses are applicable and bounding for a site by providing a comparison of plant-specific*

parameters (e.g., dimensional assumptions for the divider plate, channel head, tube sheet and stub runner; material assumptions for the bottom head and cladding, upper vessel wall, tubesheet, stub runner, divider plate and welds; design and transient loads) to the values provided in the industry analyses. One such method to provide this comparison is to use the checklist provided in the EPRI letter SGMP-IL-16-02 (EPRI 2016-TN11519).

- *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the industry analyses (EPRI 2014-TN8060) are not bounding for the applicant's unit, use of the One-Time Inspection AMP is necessary or a rationale should be provided for why such a program is not needed. The One-Time Inspection AMP (in addition to the Water Chemistry and the Steam Generator AMP) should include an inspection that is capable of detecting cracking to verify the effectiveness of the Water Chemistry and Steam Generator AMP 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 AMP). The GALL-SLR Report recommends further evaluation for the use of the One-Time Inspection AMP to confirm the effectiveness of the Water Chemistry and Steam Generator AMPs as described in this section. In place of the One-Time Inspection AMP, the applicant may provide a rationale to justify why the One-Time Inspection AMP is not necessary.

Table 3.1.1 Item Number 3.1.1-025: This item is applicable to PWRs only and therefore is not used for NMP1.

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 as follows:*

For units with Alloy 600 SG tubes with permanently approved alternate repair criterion such as C, F*, H*, or W* for both the hot- and cold-leg side of the SG, the weld is no longer part of the reactor coolant pressure boundary (RCPB) and use of the One-Time Inspection 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 if the permanent approval applies to only the hot- or cold-leg side of the SG, use of the One-Time Inspection AMP is necessary;*

For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 690 type material, use of the One-Time Inspection AMP is not necessary.

For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 600 type material, use of the One-Time Inspection 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 [EPRI 2014-TN8060]) 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 AMP. In lieu of using the One-Time Inspection AMP, the applicant

may provide a rationale for why use of the One-Time Inspection 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 Water Chemistry and Steam Generator AMPs, the One-Time Inspection AMP should be evaluated to confirm the effectiveness of the Water Chemistry and Steam Generator AMPs in certain circumstances. The One-Time Inspection AMP should include an inspection that is capable of detecting cracking to confirm the absence of PWSCC in the tube-to-tubesheet welds. In place of the One-Time Inspection AMP, the applicant may provide a rationale to justify why the One-Time Inspection AMP is not necessary.

Table 3.1.1 Item Number 3.1.1-025: This item is applicable to PWRs only and therefore is not used for NMP1.

3.1.2.2.12 Cracking Due to Irradiation-Assisted Stress Corrosion Cracking

Deleted.

3.1.2.2.13 Loss of Fracture Toughness Due to Neutron Irradiation or Thermal Aging Embrittlement

Deleted.

3.1.2.2.14 Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation

The GALL-SLR Report AMP XI.M9 manages loss of preload due to thermal or irradiation enhanced stress relaxation in BWR core plate rim hold-down bolts. The issue is applicable to BWR designed light-water reactors that employ rim hold-down 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 DBA 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.

The GALL-SLR Report AMP XI.M9 indicates that the inspections in the Boiling Water Reactor Vessel and Internals Project (BWRVIP) TR, "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 hold-down 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 hold-down 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 hold-down 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) (TN4878). Additionally, Appendix I of BWRVIP-25, Revision 1-A documents a comprehensive evaluation that provides justification for the elimination of periodic core plate bolt inspections for many boiling water reactors. An applicant relying on this report to eliminate periodic core plate bolt inspections must demonstrate the criteria provided in Appendix I of BWRVIP-25, Revision 1-A are met at the time of the renewal application. This evaluation may need to be identified as TLAAs if it is determined to conform to the six criteria for defining TLAAs in 10 CFR 54.3(a). See SRP-SLR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c). 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.

Table 3.1.1 Item Number 3.1.1-120: This item evaluates loss of preload due to thermal or irradiation-enhanced stress relaxation in stainless steel core plate rim hold-down bolts exposed to reactor coolant with neutron flux. NMP1 uses core plate wedges as the means of precluding lateral movement of the core plate. The core plate wedges are fixed in place and are not subject to loss of preload due to thermal or irradiation-enhanced stress relaxation. Therefore, inspections of the core plate rim hold-down bolt are not required.

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 highly alkaline 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 penetrate 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: (i) 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 (NRC 1996-TN8063); (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) 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.

Table 3.1.1 Item Number 3.1.1-105: Not applicable. This item evaluates steel piping and piping components exposed to concrete. There are no steel piping or piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System at NMP1.

Table 3.1.1 Item Number 3.1.1-115: Not applicable. This item evaluates stainless steel piping and piping components exposed to concrete. There are no stainless steel piping or piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System at NMP1.

3.1.2.2.16 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: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) 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 that requires management for SS and nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) 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 in the presence 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 a systems, structures, and components (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 mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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 for internal or external coatings.

Table 3.1.1 Item Number 3.1.1-136: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping and piping components exposed to air and condensation. There are no stainless steel or nickel alloy piping or piping components exposed to air-outdoor, air indoor controlled, or condensation in the Reactor Vessel, Internals, and Reactor Coolant System at NMP1. Plant-specific OE from 2016 to 2026 associated with stainless steel and nickel alloy piping and piping components has been evaluated to determine if prolonged exposure to air-indoor uncontrolled has resulted in loss of material due to pitting or crevice corrosion. This review did not identify loss of material for this material and environment combination at NMP1. This provides objective evidence that the external surfaces of components in this environment are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, the One-Time Inspection (B.2.1.20) program will be implemented to demonstrate that the aging effect of loss of material is not occurring in stainless steel and nickel alloy piping and piping components exposed to air-indoor uncontrolled in the Reactor Pressure Vessel, Reactor Coolant Pressure Boundary System, and Reactor Pressure Vessel Instrumentation System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

3.1.2.2.17 Cracking Due to Thermal Fatigue

As addressed in NRC Bulletin 88-08, non-isolable branch lines connected to the RCS may be subject to unacceptable thermal stress that can cause thermal fatigue cracking and leakage failure (NRC 1988-TN8082). The NRC Bulletin 88-08 states that, when such piping is identified, actions should be taken to ensure that the piping will not be subject to unacceptable thermal stress.

Industry OE and evaluation indicate that in some branch lines, thermal stratification or mixing cycles can occur due to the interaction between the hot swirl penetration from the RCS and the cold water in-leakage from a leaking valve (EPRI 2019-TN8083, McDevitt

et al. 2015-TN8105, Duke Energy 2014-TN8106, EPRI 2016-TN8114, EPRI 2018-TN8115). In other branch lines, thermal stratification or mixing cycles can result from the interaction of the hot swirl penetration and the cold water in the normally cool, stagnant branch lines without a leaking valve. In addition, cold or hot fluid injections can cause thermal fatigue in the RCS as indicated in ASME Code Case N-716-1 (ASME 2014-TN8107). Therefore, cracking due to thermal fatigue can occur due to cyclic stresses from the thermal stratification, mixing or injection cycles.

The industry guidance to manage the thermal fatigue in the PWR branch lines is described in EPRI MRP-146, Revision 2 (EPRI 2016-TN8114). The guidance provides methods for screening and evaluating the susceptibility of non-isolable branch lines to thermal fatigue. The MRP-146, Revision 2 also provides general guidance for monitoring valve in-leakage and thermal stress as needed and performing volumetric examinations on the susceptible locations (e.g., examination areas, volumes, and frequencies). These guidelines continue to be enhanced based on the lessons learned from relevant OE and research activities. The BWRVIP-155, Revision 1 also describes the evaluation of thermal fatigue susceptibility in the branch lines of BWR RCPB (EPRI 2018-TN8115).

In addition, the existing aging management at plants may rely on the risk-informed ISI that includes examination of the RCPB locations susceptible to thermal fatigue.

As discussed above, cracking due to thermal fatigue can occur in the RCS. The applicant should perform further evaluation to confirm the adequacy of a plant-specific AMP for management of the aging effect (e.g., adequate selection of susceptible locations for inspections, timely detection of cracks, and preventive action for valve in-leakage as needed). The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP.

Table 3.1.1 Item Number 3.1.1-140: This item evaluates cracking due to thermal fatigue of steel, stainless steel, or nickel alloy non-isolable branch lines connected to the reactor coolant system. NRC Bulletin 88-08 requested that licensees review their reactor coolant system piping to identify any connected, unisolable piping that could be subjected to temperature distributions which would result in unacceptable thermal stresses. Nine Mile Point Nuclear Station, Unit 1 originally responded to NRC Bulletin 88-08 by letters dated September 29, 1988 (ADAMS Accession No. ML17055E226) and December 16, 1991 (ADAMS Accession No. ML17056B573). The initial NMP1 response identified several piping configurations as having the potential for thermal cyclic fatigue including the reactor head spray line, the feedwater system at the feedwater nozzles and the reactor water cleanup mixing tee, and the emergency cooling system condensate return line. NMP1 dispositioned thermal cyclic fatigue concerns in the reactor head spray and feedwater lines by a combination of design changes, operational changes, and non-destructive examinations. Fatigue concerns were originally dispositioned in the emergency cooling system lines by non-destructive testing, evaluation of thermal stratification and mixing, and commitments for continued monitoring of leakage past the emergency condenser isolation valves.

Nine Mile Point Nuclear Station, Unit 1 provided further supplement to the NRC Bulletin 88-08 response in a letter dated July 20, 1992 (ADAMS Accession No. ML17058B001) due to the discovery of cracking in a limited number of valves in the emergency condenser return lines. The affected valves were two gate valves and a check valve

downstream of the air operated isolation valves in each emergency condenser loop. Metallurgical examinations of crack samples from the valves concluded that intermittent thermal stratification was a credible cause for the cracking. While the system was disassembled for repairs, NMP1 performed visual examinations of the inside bottom surface of the unisolable emergency condenser return piping, including the lower inner radius of the reactor recirculation tee. No indications were identified during this examination. This section of unisolable emergency condenser return piping was previously inspected by UT in 1988 with no indications identified.

Further correspondence dated June 29, 1994 (ADAMS Accession No. ML17059A342) provided a summary of the causal factors of the fatigue cracking discovered in the emergency condenser return line valves. One of the major contributing factors for thermal stratification and cycling was determined to be leakage of cold water through the air operated isolation valves in both emergency condenser loops. The air operated isolation valves were subsequently modified to improve seating and reduce leakage. Nine Mile Point Nuclear Station, Unit 1 continues to perform temperature monitoring and trending activities for the emergency condensers and associated piping. Specific acceptance criteria are included for the emergency condenser return piping to ensure temperature distributions that could degrade the structural integrity of the piping are not exceeded. Temperature monitoring activities will continue to be implemented through the Water Chemistry (B.2.1.2) program for subsequent license renewal. Additional discussion of emergency condenser temperature monitoring is provided in Further Evaluation sections 3.1.2.2.4.2 and 3.1.2.2.7.

BWRVIP-155, Revision 1 provides the most recent industry guidance for the screening and evaluation of thermal fatigue susceptibility in BWR non-isolable, normally stagnant branch lines. BWRVIP-155, Revision 1 recommends that all normally stagnant branch piping greater than one inch nominal pipe size attached to the bottom (or within the lower circumferential arc) of the recirculation and feedwater piping be screened to determine the impact of cyclic swirl penetration. BWRVIP-155, Revision 1 refers to these piping configurations as down horizontal (DH). Constellation addressed the recommendations of BWRVIP-155 in a fleet wide effort. A review of relevant NMP1 P&IDs and piping isometrics was performed, which concluded that NMP1 has no normally stagnant branch piping greater than 1 inch nominal pipe size attached to the bottom (or within the lower circumferential arc) of the recirculation or feedwater piping.

BWRVIP-155, Revision 1 generally suggests that stagnant branch lines in the up horizontal (UH) or horizontal (H) configuration do not need to be screened for thermal stratification or cycling, as these configurations are expected to run hot at all times due to natural convection. BWRVIP-155, Appendix A discusses the fatigue cracking identified in the NMP1 emergency condenser return lines (in 1992) as a unique situation where fatigue cracking occurred in a branch line with a UH/H configuration. This case was attributed to cold water in-leakage from the emergency condensers. As discussed above, NMP1 performs temperature monitoring and trending activities for the emergency condenser return lines to ensure temperature distributions that could degrade the structural integrity of the piping are not exceeded.

Based on the evaluations performed following the guidance of BWRVIP-155, Revision 1 and the temperature monitoring activities performed for the emergency condensers being implemented by the Water Chemistry (B.2.1.2) program, it is concluded that a plant

specific aging management program is not required to manage the aging effect of cracking due to thermal fatigue in reactor coolant system branch lines.

3.1.2.2.18 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Section B.1.3.

3.1.2.2.19 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, section A.1.6 and Appendix B, Section B.1.4.

3.1.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Reactor Vessel, Internals, and Reactor Coolant System components:

- Section 4.2.1.1, Reactor Pressure Vessel Neutron Fluence Analyses
- Section 4.2.1.2, Reactor Pressure Vessel Internals Neutron Fluence Analyses
- Section 4.2.2, Reactor Pressure Vessel Upper Shelf Energy (USE) Analyses
- Section 4.2.3, Reactor Pressure Vessel Adjusted Reference Temperature (ART) Analyses
- Section 4.2.4, Reactor Pressure Vessel Pressure-Temperature (P-T) Limits
- Section 4.2.5, Reactor Pressure Vessel Circumferential Weld Failure Probability Analysis
- Section 4.2.6, Reactor Pressure Vessel Axial Weld Failure Probability Analyses
- Section 4.2.7, Core Shroud Stabilizer Assembly Preload Relaxation Analysis
- Section 4.3.1, Transient Cycle and Cumulative Usage Projections for 80 Years
- Section 4.3.2, Reactor Vessel and Piping Fatigue Analyses
- Section 4.3.3, Fatigue of the Emergency Condensers
- Section 4.3.4, ASME Section III, Class 2 and 3, and ANSI B31.1 Allowable Stress Analysis and HELB Exclusions of Recirculation Piping Analysis
- Section 4.3.5, Environmentally Assisted Fatigue Analysis
- Section 4.3.6, Reactor Vessel Internals Fatigue Analyses
- Section 4.3.6.1, Core Shroud Stabilizer Tie-Rod and Conical Support Fatigue Analysis
- Section 4.3.6.2, Core Shroud Vertical Weld Repair Clamps Fatigue Analysis
- Section 4.3.6.3, Core Shroud Stabilizer Modified Upper Supports Fatigue Analyses
- Section 4.3.6.4, Steam Dryer Support Bracket Fatigue Analysis
- Section 4.7.1.1, Reactor Vessel Flaw Evaluations

- Section 4.7.1.2, Reactor Vessel Closure Head Flaw Evaluations
- Section 4.7.3, Generic Letter 81-11, “Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking””
- Section 4.7.7, CRD Bottom Head Penetrations Fracture Mechanics Analysis
- Section 4.7.9, Core Shroud Tie-Rod X-750 Inconel Component Service Life

3.1.3 CONCLUSION

The Reactor Vessel, Internals, and Reactor Coolant System piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Reactor Vessel, Internals, and Reactor Coolant System components are identified in the summaries in Section 3.1.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Vessel, Internals, and Reactor Coolant System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-001	Steel reactor vessel (RV) closure flange assembly components exposed to air-indoor uncontrolled	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, Standard Review Plan for Review of Subsequent License Renewal (SRP-SLR) Section 4.3 "Metal Fatigue"	Yes	Cumulative fatigue damage is evaluated as a TLAA; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-002	PWR Only				
3.1.1-003	Stainless steel (SS), nickel alloy reactor vessel internal (RVI) 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	Cumulative fatigue damage is evaluated as a TLAA; further evaluation is documented in Subsection 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	Cumulative fatigue damage is evaluated as a TLAA; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-005	PWR Only				
3.1.1-006	SS, steel (with or without nickel alloy or stainless steel cladding), nickel alloy RCPB 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	Cumulative fatigue damage is evaluated as a TLAA; further evaluation is documented in Subsection 3.1.2.2.1.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-007	SS, steel (with or without nickel alloy or SS cladding), nickel-alloy RV 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	Cumulative fatigue damage is evaluated as a TLAA; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-008	PWR Only				
3.1.1-009	PWR Only				
3.1.1-010	PWR Only				
3.1.1-011	Steel or SS 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	Cumulative fatigue damage is evaluated as a TLAA; further evaluation is documented in Subsection 3.1.2.2.1.
3.1.1-012	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-013	Steel (with or without stainless steel or nickel- alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, SRP-SLR Section 4.2 "Reactor Pressure Vessel Neutron Embrittlement Analyses"	Yes	Loss of fracture toughness due to neutron irradiation embrittlement is evaluated as a TLAA; further evaluation is documented in Subsection 3.1.2.2.3.1.
3.1.1-014	Steel (with or without cladding) reactor vessel beltline shell, nozzle, and weld components, exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	AMP XI.M31, "Reactor Vessel Material Surveillance," and AMP X.M2, "Neutron Fluence Monitoring"	Yes	Consistent with NUREG-2191. The Neutron Fluence Monitoring (B.3.1.2) and Reactor Vessel Material Surveillance (B.2.1.19) program will be used to manage loss of fracture toughness of the carbon or low alloy steel with stainless steel cladding reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel. See Subsection 3.1.2.2.3.2.
3.1.1-015	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-016	SS or nickel- alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled, reactor coolant leakage	Cracking due to SCC, intergranular stress corrosion cracking (IGSCC)	AMP XI.M32, "One-Time Inspection;" or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the stainless steel reactor vessel flange leak detection line, reactor vessel penetrations, nozzles, safe ends, and welds exposed to air-indoor, uncontrolled in the Reactor Pressure Vessel and Reactor Pressure Vessel Instrumentation System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.1.2.2.4.1.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-017	SS 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	Consistent with NUREG-2191 with exceptions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) programs are used to manage cracking of the stainless steel emergency condenser tubes and tubesheets in the Emergency Cooling System. Supplemental testing and inspections are performed to monitor for cracking including radioactivity and temperature monitoring of the shell side water and visual inspection of the accessible outer surfaces of the tubes and the shell side of the tubesheets. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. See Subsection 3.1.2.2.4.2.
3.1.1-018	PWR Only				
3.1.1-019	PWR Only				
3.1.1-020	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-021	Steel and SS 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	Consistent with NUREG-2191. The ASME Section XI IWB, IWC, and IWD (B.2.1.1) program is used to manage cracking of the stainless steel emergency condenser tubes and tubesheets in the Emergency Cooling System. Supplemental testing and inspections are performed to monitor for cracking including radioactivity and temperature monitoring of the shell side water and visual inspection of the accessible outer surfaces of the tubes and the shell side of the tubesheets. The radioactivity and temperature monitoring of the emergency condenser shell side water is implemented through the Water Chemistry (B.2.1.2) program. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. See Subsection 3.1.2.2.7.
3.1.1-022	PWR Only				
3.1.1-023	This Item Number is not listed in NUREG-2192.				
3.1.1-024	This Item Number is not listed in NUREG-2192.				
3.1.1-025	PWR Only				
3.1.1-026	This Item Number is not listed in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-027	This Item Number is not listed in NUREG-2192.				
3.1.1-028	PWR Only				
3.1.1-029	Nickel-alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	No	Not Applicable. The NMP1 reactor vessel internals design does not include core shroud and core plate access hole covers.
3.1.1-030	SS, 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	Consistent with NUREG-2191 with exceptions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and stainless steel high pressure seal leak detector nozzle and welds exposed to reactor coolant in the Reactor Pressure Vessel. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-031	Steel and SS 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	Consistent with NUREG-2191 with exceptions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) programs will be used to manage loss of material of the stainless steel emergency condenser tubes and tubesheets in the Emergency Cooling System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-032	This Item Number is not listed in NUREG-2192.				
3.1.1-033	PWR Only				
3.1.1-034	PWR Only				
3.1.1-035	PWR Only				
3.1.1-036	PWR Only				
3.1.1-037	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-038	CASS 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. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will be used to manage loss of fracture toughness of the cast austenitic stainless steel (CASS) valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F) in the Reactor Coolant Pressure Boundary System.
3.1.1-039	SS, steel (with or without nickel-alloy or SS cladding), nickel-alloy Class 1 piping, fittings and branch connections < nominal pipe size (NPS) 4 exposed to reactor coolant	Cracking due to SCC (for SS 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. The ASME Code Class 1 Small-Bore Piping (B.2.1.22), ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), and Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon steel and stainless steel Class 1 piping, fittings, and branch connections < 4" NPS exposed to reactor coolant, steam, treated water, and treated water > 140°F in the Reactor Coolant Pressure Boundary System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-040	PWR Only				
3.1.1-040a	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-041	Nickel-alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	No	Not Applicable. The NMP1 reactor vessel internals design does not include core shroud and core plate access hole covers.
3.1.1-042	PWR Only				
3.1.1-043	SS and nickel-alloy RVI 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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) program has been substituted for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, and will be used with the Water Chemistry (B.2.1.2) program to manage loss of material of the cast austenitic stainless steel (CASS), nickel alloy, and stainless steel reactor vessel nozzle thermal sleeves and reactor vessel internals exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Reactor Pressure Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-044	PWR Only				
3.1.1-045	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-046	PWR Only				
3.1.1-047	PWR Only				
3.1.1-048	PWR Only				
3.1.1-049	PWR Only				
3.1.1-050	CASS 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. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8) program will be used to manage loss of fracture toughness of the CASS reactor recirculation pump casings exposed to reactor coolant >250 °F (>482 °C) in the Reactor Coolant Pressure Boundary System.
3.1.1-051a	PWR Only				
3.1.1-051b	PWR Only				
3.1.1-052a	PWR Only				
3.1.1-052b	PWR Only				
3.1.1-052c	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-053a	PWR Only				
3.1.1-053b	PWR Only				
3.1.1-053c	PWR Only				
3.1.1-054	PWR Only				
3.1.1-055a	PWR Only				
3.1.1-055b	PWR Only				
3.1.1-055c	PWR Only				
3.1.1-056a	PWR Only				
3.1.1-056b	PWR Only				
3.1.1-056c	PWR Only				
3.1.1-057	This Item Number is not listed in NUREG-2192.				
3.1.1-058a	PWR Only				
3.1.1-058b	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-059a	PWR Only				
3.1.1-059b	PWR Only				
3.1.1-059c	PWR Only				
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	Consistent with NUREG-2191 with exceptions. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel piping components exposed to reactor coolant in the Reactor Coolant Pressure Boundary System. Exceptions apply to the NUREG-2191 recommendations for Flow-Accelerated Corrosion (B.2.1.9) program implementation.
3.1.1-061	PWR Only				
3.1.1-062	High-strength steel, SS closure bolting; SS control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.1.10) program will be used to manage cracking of the stainless steel bolting exposed to air-indoor, uncontrolled in the Reactor Coolant Pressure Boundary System.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-063	Steel or SS 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. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel and stainless steel bolting exposed to air-indoor, uncontrolled in the Reactor Coolant Pressure Boundary System, Reactor Pressure Vessel, and Reactor Pressure Vessel Instrumentation System.
3.1.1-064	PWR Only				
3.1.1-065	PWR Only				
3.1.1-066	PWR Only				
3.1.1-067	Steel or SS 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. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of the carbon and low alloy steel and stainless steel bolting exposed to air-indoor, uncontrolled in the Reactor Coolant Pressure Boundary System, Reactor Pressure Vessel, and Reactor Pressure Vessel Instrumentation System.
3.1.1-068	PWR Only				
3.1.1-069	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-070	PWR Only				
3.1.1-071	PWR Only				
3.1.1-072	PWR Only				
3.1.1-073	PWR Only				
3.1.1-074	PWR Only				
3.1.1-075	PWR Only				
3.1.1-076	PWR Only				
3.1.1-077	PWR Only				
3.1.1-078	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-079	SS; steel with nickel-alloy or SS cladding; and nickel-alloy RCPB 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. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the cast austenitic stainless steel (CASS) and stainless steel components exposed to reactor coolant and steam in the Reactor Coolant Pressure Boundary System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-080	PWR Only				
3.1.1-081	PWR Only				
3.1.1-082	PWR Only				
3.1.1-083	PWR Only				
3.1.1-084	Steel top head enclosure (without cladding): top head, top head nozzles (vent, top head spray, reactor core isolation cooling, spare) exposed to reactor coolant	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel nozzles, safe ends, and welds exposed to reactor coolant in the Reactor Pressure Vessel. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-085	SS, nickel-alloy, and steel with nickel-alloy or SS 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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads, and welds exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-086	PWR Only				
3.1.1-087	PWR Only				
3.1.1-088	PWR Only				
3.1.1-089	PWR Only				
3.1.1-090	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-091	Steel (including high-strength steel) RV 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. The Reactor Head Closure Stud Bolting (B.2.1.3) program will be used to manage cracking and loss of material of the high strength low alloy steel bolting with yield strength of 150 ksi or greater reactor vessel closure flange assembly components exposed to air - indoor, uncontrolled in the Reactor Pressure Vessel.
3.1.1-092	PWR Only				
3.1.1-093	PWR Only				
3.1.1-094	SS 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	Consistent with NUREG-2191 with exceptions. The BWR Vessel ID Attachment Welds (B.2.1.4) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and stainless steel reactor vessel internal attachments exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel. Exceptions apply to the NUREG 2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-095	Steel (with or without SS 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	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will be used to manage cracking of the carbon steel feedwater nozzles exposed to reactor coolant in the Reactor Pressure Vessel.
3.1.1-096	Steel (with or without SS 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 Used. Control rod drive return line nozzles and nozzle-to-vessel welds are addressed by item number 3.1.1-114.
3.1.1-097	SS and nickel-alloy piping, piping components ≥ 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 exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel Class 1 piping components greater than or equal to 4" NPS exposed to reactor coolant in the Reactor Coolant Pressure Boundary System. Exceptions apply to the NUREG 2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-098	SS, nickel-alloy penetrations: CRD stub tubes, in core monitor housing, 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	Consistent with NUREG-2191 with exceptions. The BWR Penetrations (B.2.1.6) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and stainless steel penetrations (instrumentation, core differential pressure and SLC, control rod drive, and in core monitor housing) exposed to reactor coolant in the Reactor Pressure Vessel. Exceptions apply to the NUREG 2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-099	SS (including CASS; PH martensitic SS; martensitic SS); 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"	No	Consistent with NUREG-2191. The BWR Vessel Internals (B.2.1.7) program will be used to manage loss of fracture toughness of the cast austenitic stainless steel (CASS) components exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel Internals. The BWR Vessel Internals (B.2.1.7) program utilizes the guidance provided by BWRVIP-315-A.
3.1.1-100	SS RVI components (jet pump wedge surface) exposed to reactor coolant	Loss of material due to wear	AMP XI.M9, "BWR Vessel Internals"	No	Not Applicable. The NMP1 BWR design does not include jet pump assemblies.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-101	SS 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	Consistent with NUREG-2191. The BWR Vessel Internals (B.2.1.7) program will be used to manage cracking of the stainless steel steam dryers and bolted/welded clamp repairs exposed to reactor coolant in the Reactor Pressure Vessel Internals.
3.1.1-102	SS 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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the cast austenitic stainless steel (CASS) and stainless steel fuel supports, control rod drive assemblies, control rod drive housings, and core spray sparger nozzle elbows exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel Internals. Exceptions apply to the NUREG 2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-103	SS, nickel-alloy reactor internal components exposed to reactor coolant and neutron flux	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.1.7) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and stainless steel reactor internal components exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel and Reactor Pressure Vessel Internals. The BWR Vessel Internals (B.2.1.7) program utilizes the guidance provided by BWRVIP-315-A. Exceptions apply to the NUREG 2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-104	Nickel-alloy RVI 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 Used. Cracking of nickel alloy reactor internal components exposed to reactor coolant and neutron flux is addressed by Item Number 3.1.1-103.
3.1.1-105	Steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no steel piping or piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System. See Subsection 3.1.2.2.15.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-106	Nickel-alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel alloy piping or piping components exposed to air with borated water leakage in the Reactor Vessel, Internals, and Reactor Coolant System.
3.1.1-107	SS piping, piping components exposed to gas, air with borated water leakage	None	None	No	Consistent with NUREG-2191.
3.1.1-108	This Item Number is not listed in NUREG-2192.				
3.1.1-109	This Item Number is not listed in NUREG-2192.				
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. There are no metallic piping or piping components exposed to reactor coolant in Reactor Vessel, Internals, and Reactor Coolant System.
3.1.1-111	PWR Only				
3.1.1-112	This Item Number is not listed in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-113	Steel RV 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	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will be used to manage loss of material of the carbon steel reactor vessel external surfaces and external attachments exposed to air-indoor, uncontrolled in the Reactor Pressure Vessel.
3.1.1-114	RCS components defined as ASME Section XI Code Class components (ASME Code Class 1 RCPB components, RVI attachments, or core support structure components; or ASME Class 2 or 3 components-including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME Code classes)	Cracking due to SCC, IGSCC, primary water stress corrosion cracking (PWSCC), IASCC (SCC mechanisms for SS, nickel-alloy components only), fatigue, or cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, or wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (water chemistry-related or corrosion-related aging effect mechanisms only)	No	Consistent with NUREG-2191 with exceptions. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon or low alloy steel with stainless steel cladding, cast austenitic stainless steel (CASS), nickel alloy, and stainless steel components defined as ASME Section XI Code Class components (ASME Code Class 1 RCPB components, RVI attachments, or core support structure components; or ASME Class 2 or 3 components-including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME Code classes) exposed to reactor coolant, steam, and neutron flux in the Reactor Coolant Pressure Boundary System and Reactor Pressure Vessel. Exceptions apply to the NUREG 2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-115	SS piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no stainless steel piping or piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System. See Subsection 3.1.2.2.15.
3.1.1-116	PWR Only				
3.1.1-117	PWR Only				
3.1.1-118	PWR Only				
3.1.1-119	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-120	SS core plate rim hold-down 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 TLAA's" [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	Consistent with NUREG-2191. The BWR Vessel Internals (B.2.1.7) program will be used to manage loss of preload of the stainless steel core plate rim hold-down bolts, core plate guide tube plugs, core shroud repair hardware, and steam dryer repair hardware exposed to reactor coolant and neutron flux in the Reactor Pressure Vessel Internals. NMP1 uses core plate wedges as the means of precluding lateral movement of the core plate. The core plate wedges are fixed in place and are not subject to loss of preload. Therefore, inspections of the core plate rim hold-down bolts are not required per BWRVIP-25, Revision 1-A. See Subsection 3.1.2.2.14.
3.1.1-121	SS jet pump assembly hold-down 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. The NMP1 BWR design does not include jet pump assemblies.
3.1.1-122	This Item Number is not listed in NUREG-2192.				
3.1.1-123	This Item Number is not listed in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon steel flow device, piping, and piping components exposed to air-indoor, uncontrolled in the Reactor Coolant Pressure Boundary System. The aging effect of loss of material due to general corrosion does not apply to the carbon steel external surfaces of reactor vessel, nozzle, and safe end components exposed to air-indoor, uncontrolled in the Reactor Pressure Vessel system. During power operation the insulated reactor vessel, nozzles, and safe end components have external temperature greater than 212 degrees F and are at a higher temperature than the air-indoor (uncontrolled) environment. During plant shutdown the containment atmosphere is normally above the dewpoint temperature. Therefore, wetting due to condensation and moisture accumulation will not occur during power operation or plant outages and loss of material due to general corrosion does not apply.
3.1.1-125	PWR Only				
3.1.1-126	This Item Number is not listed in NUREG-2192.				
3.1.1-127	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-128	SS, 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	Consistent with NUREG-2191 with exceptions. The BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the nickel alloy and stainless steel nozzles, safe ends, and welds exposed to reactor coolant in the Reactor Pressure Vessel. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.1.1-129	Steel and SS 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. The current NMP1 design does not include re-routed control rod drive return lines to the reactor vessel. The original control rod drive return line is intact.
3.1.1-130	This Item Number is not listed in NUREG-2192.				
3.1.1-131	This Item Number is not listed in NUREG-2192.				
3.1.1-132	This Item Number is not listed in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage long-term loss of material of the carbon steel components exposed to reactor coolant and treated water in the Reactor Coolant Pressure Boundary System and Reactor Pressure Vessel. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation.
3.1.1-134	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Used. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic thermal insulation exposed to air-indoor uncontrolled as addressed by Item Number 3.4.1-064. Thermal insulation is addressed as a commodity in the Insulation Commodity Group System.
3.1.1-135	This Item Number is not listed in NUREG-2192.				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-136	SS, 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the cast austenitic stainless steel (CASS), nickel alloy, and stainless steel flow devices, piping and piping components, pump casings, valve bodies, penetrations, nozzles, safe ends, and welds exposed to air-indoor, uncontrolled in the Reactor Coolant Pressure Boundary System, Reactor Pressure Vessel, and Reactor Pressure Vessel Instrumentation System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.1.2.2.16.
3.1.1-137	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Not Applicable. There are no copper alloy piping or piping components exposed to air, condensation, or gas in the Reactor Vessel, Internals, and Reactor Coolant System.
3.1.1-138	This Item Number is not listed in NUREG-2192.				
3.1.1-139	PWR Only				

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-140	Steel, SS or nickel-alloy piping, piping components exposed to reactor coolant	Cracking due to thermal fatigue	Plant-specific aging management program	Yes	Consistent with NUREG-2191 with exceptions. NMP1 performed an evaluation of reactor coolant system piping to identify any branch lines with potential thermal fatigue susceptibility. The evaluation followed the guidance of BWRVIP-155, Revision 1. The evaluation did not identify any stagnant branch lines in the down horizontal (DH) configuration at NMP1 with thermal fatigue susceptibility. Temperature monitoring and trending activities are performed for the stainless steel emergency condenser return lines exposed to reactor coolant to identify temperature distributions that could damage the structural integrity of the piping. Temperature monitoring activities are implemented through the Water Chemistry (B.2.1.2) program for subsequent license renewal. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. See Subsection 3.1.2.2.17.

Table 3.1.1 Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-141	Steel, SS or nickel-alloy ASME Code Class 1 small-bore piping, and piping with reflective metal insulation exposed to air	Loss of material due to wear	Plant-specific or existing aging management program if loss of material is not mitigated	Yes	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material due to wear of steel, stainless steel, or nickel alloy ASME Code Class 1 small-bore piping with reflective metal insulation exposed to air. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.1.2.2.10.3.

Table 3.1.2-1 Control Rod Drive System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36069	Accumulator (Hydraulic Control Unit)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
36070	Accumulator (Hydraulic Control Unit)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
36071	Accumulator (Hydraulic Control Unit)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
36072	Accumulator (Hydraulic Control Unit)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
36077	Accumulator (Hydraulic Control Unit)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
36065	Accumulator (Nitrogen Tank)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
36066	Accumulator (Nitrogen Tank)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
36067	Accumulator (Nitrogen Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
36068	Accumulator (Nitrogen Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
34456	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
34457	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38061	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
38062	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
38063	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36055	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
36056	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
36057	Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
36058	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B

Table 3.1.2-1 Control Rod Drive System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36059	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
36060	Flow Device	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
35348	Gearbox	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35347	Gearbox	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-127	3.3.1-097	C
36050	Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Heat Transfer	Cast Iron	Lubricating Oil (Internal)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	VII.E4.A-791	3.3.1-257	A
36051	Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Heat Transfer	Cast Iron	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)			H, 1
35238	Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35243	Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-131	3.3.1-098	A
35245	Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
35244	Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D
35246	Heat Exchanger – (Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E4.AP-31	3.3.1-072	D
35249	Heat Exchanger – (Pump Gear Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 2
35300	Heat Exchanger – (Pump Gear Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-133	3.3.1-099	C
36042	Heat Exchanger – (Pump Gear Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-133	3.3.1-099	C
36043	Heat Exchanger – (Pump Gear Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	D
36048	Heat Exchanger – (Pump Gear Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.F1.AP-65	3.3.1-072	B

Table 3.1.2-1 Control Rod Drive System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36099	Heat Exchanger – (Pump Gear Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36101	Heat Exchanger – (Pump Gear Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
36100	Heat Exchanger – (Pump Gear Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D
36102	Heat Exchanger – (Pump Gear Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E4.AP-31	3.3.1-072	D
35301	Heat Exchanger – (Pump Gear Oil Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	VII.E4.A-791	3.3.1-257	A
35318	Heat Exchanger – (Pump Gear Oil Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	VIII.E.SP-100	3.4.1-018	B
35327	Heat Exchanger – (Pump Gear Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-133	3.3.1-099	C
35328	Heat Exchanger – (Pump Gear Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	D
36061	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
36062	Piping elements	Leakage Boundary (Spatial)	Glass	Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
34792	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35330	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
34793	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
34789	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
34790	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
34791	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.1.2-1 Control Rod Drive System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34826	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35331	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
34830	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
34787	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
34788	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
35390	Piping, piping components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35391	Piping, piping components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
34786	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
34784	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
34785	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
34782	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34783	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-26	3.3.1-055	A
34779	Pump Casing (Control Rod Drive Pump)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36330	Pump Casing (Control Rod Drive Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
34780	Pump Casing (Control Rod Drive Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
35332	Rupture Disks	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35333	Rupture Disks	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B

Table 3.1.2-1 Control Rod Drive System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35335	Rupture Disks	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35336	Rupture Disks	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
34778	Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
35337	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35339	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
35338	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
37416	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
37417	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
37418	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
34820	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35342	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
34821	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
34773	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
34774	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
35343	Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35344	Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
35041	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
34771	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B

Table 3.1.2-1 Control Rod Drive System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34772	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
34795	Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34796	Valve Body	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-26	3.3.1-055	A

Table 3.1.2-1 Control Rod Drive System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The Water Chemistry (B.2.1.2) program is used to manage the aging effect(s) applicable to this component type, material, and environment combination which is consistent with managing this aging effect in this environment for other materials.
2. The review of 10-years of plant specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33606	Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
33607	Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
33609	Bolting (Class 1)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1.1-062	B
33610	Bolting (Class 1)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
33611	Bolting (Class 1)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
33603	Flow Device (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1.1-124	A
33613	Flow Device (Class 1)	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
33612	Flow Device (Class 1)	Pressure Boundary	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
35748	Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
35749	Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
35745	Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
35744	Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
38338	Flow Device (Class 1)	Throttle	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
38337	Flow Device (Class 1)	Throttle	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
37102	Flow Device (Class 1)	Throttle	Cast Austenitic Stainless Steel (CASS)	Steam (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A, 2
47102	Flow Device (Class 1)	Throttle	Cast Austenitic Stainless Steel (CASS)	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B, 2

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33605	Flow Device (Class 1)	Throttle	Cast Austenitic Stainless Steel (CASS)	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
35747	Flow Device (Class 1)	Throttle	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
35746	Flow Device (Class 1)	Throttle	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
39227	Piping and piping components with reflective metal insulation	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	One-Time Inspection (B.2.1.20)	IV.C1.R-457	3.1.1-141	B
39228	Piping and piping components with reflective metal insulation	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	One-Time Inspection (B.2.1.20)	IV.C1.R-457	3.1.1-141	B
33615	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1.1-124	A
33616	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
33617	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1.1-133	B
35455	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
33619	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1.1-060	B
33620	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
33621	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
33622	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
33624	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
33625	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1.1-133	B
35456	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
33627	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2.1-011	B

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39219	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
39220	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
39221	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1.1-097	A
49221	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-097	B
39222	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
39223	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Loss of Fracture Toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)	IV.C1.R-52	3.1.1-050	A
39224	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
33628	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
33629	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
33630	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1.1-097	A
43630	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1.1-097	B
39242	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking/Thermal Fatigue	Water Chemistry (B.2.1.2)	IV.C1.R-456	3.1.1-140	A, 3
33631	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
33632	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33633	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.B2.SP-98	3.4.1-011	B
33634	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
33635	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
36618	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
36620	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
33638	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 200°F (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	V.D2.E-37	3.2.1-054	A
43638	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 200°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-37	3.2.1-054	B
33636	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 200°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
38129	Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 200°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35091	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1.1-124	A
35720	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1.1-039	A
45720	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
55720	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking/thermal, mechanical, and vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
35092	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
35093	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1.1-133	B

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35122	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35094	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1.1-060	B
35721	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1.1-039	A
45721	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
55721	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Cracking/thermal, mechanical, and vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
35096	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
35097	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
35098	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
35723	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1.1-039	A
45723	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
55723	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cracking/thermal, mechanical, and vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
35100	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35101	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1.1-133	B
35124	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35099	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2.1-011	B
35108	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
35109	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
35105	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1.1-039	A
45105	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
55105	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
35103	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
35104	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
35131	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1.1-039	A
45131	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
55131	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
35129	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	IV.C1.R-220	3.1.1-006	A, 1
35130	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
35714	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1.1-039	A
45714	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cracking/thermal, mechanical, and vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
55714	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cracking/thermal, mechanical, and vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
35106	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
35107	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35126	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1.1-039	A
45126	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1.1-039	A
55126	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking/SCC, IGSCC, thermal, mechanical, and vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1.1-039	B
35125	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35127	Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
33659	Pump Casing (Reactor Recirculation)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
33660	Pump Casing (Reactor Recirculation)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
33661	Pump Casing (Reactor Recirculation)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
43661	Pump Casing (Reactor Recirculation)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
33663	Pump Casing (Reactor Recirculation)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Loss of Fracture Toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)	IV.C1.R-52	3.1.1-050	A
33664	Pump Casing (Reactor Recirculation)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
33665	Valve Body: Class 1	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1.1-124	A
33667	Valve Body: Class 1	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
34196	Valve Body: Class 1	Pressure Boundary	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
33669	Valve Body: Class 1	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1.1-133	B
35460	Valve Body: Class 1	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
34202	Valve Body: Class 1	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2.1-011	B
33671	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33672	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
33673	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
43673	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
33675	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1.1-038	A
33676	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
38130	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.B2.SP-98	3.4.1-011	B
38131	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
33678	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35135	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
35133	Valve Body: Class 1	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
33679	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
33680	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33681	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
43681	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
33684	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1.1-079	B
33687	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.B2.SP-98	3.4.1-011	B
33689	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
33691	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35138	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
35137	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
36861	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Treated Water > 200°F (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	V.D2.E-37	3.2.1-054	A
46861	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Treated Water > 200°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-37	3.2.1-054	B
38133	Valve Body: Class 1	Pressure Boundary	Stainless Steel	Treated Water > 200°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.1.2-2 Reactor Coolant Pressure Boundary System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA in the Aging Management Program indicates fatigue is assessed in Section 4.3
2. The internal venturi section of each main steam line flow restrictor is fabricated from centrifugally cast low molybdenum content Type 430 CASS material. Therefore, these components are not susceptible to loss of fracture toughness due to thermal aging embrittlement consistent with the screening criteria of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (B.2.1.8) program.
3. Temperature monitoring activities for the Emergency Cooling System condensate return lines are implemented through the Water Chemistry (B.2.1.2) program.

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35645	(N1 Recirculation Outlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
35642	(N1 Recirculation Outlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
45642	(N1 Recirculation Outlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
35643	(N1 Recirculation Outlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35644	(N1 Recirculation Outlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36977	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36979	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
46979	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
36981	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36982	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
35649	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
35650	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
35646	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
45646	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35647	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35648	(N1 Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
37195	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1.1-030	C
47195	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-371	3.1.1-030	D
37025	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37024	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36833	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	B
36834	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36831	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1.1-030	C
46831	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-371	3.1.1-030	D
36830	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37184	(N10 High Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36835	(N11 Low Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
36836	(N11 Low Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36838	(N11 Low Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1.1-133	B
36837	(N11 Low Pressure Seal Leak Detector) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36074	(N12 Core Differential Press.) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
35741	(N12 Core Differential Press.) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
45741	(N12 Core Differential Press.) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
35743	(N12 Core Differential Press.) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36867	(N12 Core Differential Press.) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
37030	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37031	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	C
47031	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	D
37033	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37032	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36075	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
36076	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
35763	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	C
45763	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	D
35764	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35765	(N12 Core Differential Press.) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
37034	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37035	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	C
47035	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	D
37037	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37036	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36308	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
36309	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36310	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	C
46310	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	D
36311	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36312	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36254	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzles	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36256	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzles	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
46256	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzles	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
36255	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzles	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36257	(N13, N14, N15, N16, and N17 Instrumentation) Reactor Vessel Nozzles	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36647	(N18 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
35656	(N18 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35665	(N18 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1.1-133	B
35658	(N18 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
36649	(N2 Recirculation Inlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
36720	(N2 Recirculation Inlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46720	(N2 Recirculation Inlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
35633	(N2 Recirculation Inlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35634	(N2 Recirculation Inlet) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
37042	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37043	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
47043	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
37045	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37044	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
35640	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
35641	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36722	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
46722	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
35638	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35639	(N2 Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36651	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
36725	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46725	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
35699	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35700	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36650	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
35689	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35691	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1.1-133	B
35690	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
36653	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
35703	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35705	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1.1-133	B
35704	(N3 Steam Outlet - Turbine) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
36654	(N4 Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
38197	(N4 Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-65	3.1.1-095	A
35725	(N4 Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35727	(N4 Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1.1-133	B
35726	(N4 Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
37046	(N4 Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
37047	(N4 Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37049	(N4 Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1.1-133	B
37048	(N4 Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1.1-084	D
36097	(N4 Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	C
46097	(N4 Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	D

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36096	(N4 Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36098	(N4 Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36658	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
35706	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
45706	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
35707	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35708	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
37050	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37051	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
47051	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
37053	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37052	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35718	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
35719	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36745	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
46745	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
35716	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35717	(N5 Steam Outlet - Emer. Condenser) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36660	(N6 Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
36746	(N6 Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46746	(N6 Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
35798	(N6 Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35799	(N6 Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37054	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37055	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
47055	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
37057	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37056	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
35826	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
35827	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36747	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
46747	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
35824	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35825	(N6 Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
35828	(N6 Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	A
45828	(N6 Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	B
35829	(N6 Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
35830	(N6 Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36661	(N7 Top Head Nozzles) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36124	(N7 Top Head Nozzles) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46124	(N7 Top Head Nozzles) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
36125	(N7 Top Head Nozzles) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36126	(N7 Top Head Nozzles) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
37058	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37059	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
47059	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
37061	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37060	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36205	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
36206	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36202	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46202	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
36203	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36204	(N7 Weld Neck Flanges and Blind Flanges) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
37066	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37067	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
47067	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
37069	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37068	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36858	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
36857	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36854	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1.1-128	A
6854	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1.1-128	B
36855	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37151	(N8 Vent Flange) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36914	(N8 Vent) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
36915	(N8 Vent) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46915	(N8 Vent) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
36916	(N8 Vent) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36917	(N8 Vent) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36664	(N9 CRDRL) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
36176	(N9 CRDRL) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46176	(N9 CRDRL) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
36177	(N9 CRDRL) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36178	(N9 CRDRL) Reactor Vessel Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37070	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37071	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
47071	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
37073	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
37072	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36179	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
36180	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
36181	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46181	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
36182	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36183	(N9 CRDRL) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36184	(N9 CRDRL) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	C
46184	(N9 CRDRL) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	D
36185	(N9 CRDRL) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36186	(N9 CRDRL) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36808	Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.C1.RP-44	3.1.1-011	A, 2

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36809	Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
36810	Bolting (Class 1)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
36665	Reactor Vessel (Bottom Head, Shells, Top Head, Upper Flange, and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	None	None	IV.C1.R-431	3.1.1-124	I, 1
36817	Reactor Vessel (Bottom Head, Shells, Top Head, Upper Flange, and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1.1-114	A
46817	Reactor Vessel (Bottom Head, Shells, Top Head, Upper Flange, and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1.1-114	B
36216	Reactor Vessel (Bottom Head, Shells, Top Head, Upper Flange, and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage, Cracking	TLAA	IV.A1.R-04	3.1.1-007	A, 4
36217	Reactor Vessel (Bottom Head, Shells, Top Head, Upper Flange, and Welds)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
39243	Reactor Vessel Closure Flange Assembly Components	Mechanical Closure	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor, Uncontrolled (External)	Cracking	Reactor Head Closure Stud Bolting (B.2.1.3)	IV.A1.RP-51	3.1.1-091	A
36806	Reactor Vessel Closure Flange Assembly Components	Mechanical Closure	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor, Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.A1.RP-201	3.1.1-001	A, 2
36805	Reactor Vessel Closure Flange Assembly Components	Mechanical Closure	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor, Uncontrolled (External)	Loss of Material	Reactor Head Closure Stud Bolting (B.2.1.3)	IV.A1.RP-165	3.1.1-091	A

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36829	Reactor Vessel External Surfaces and External Attachments	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	IV.A1.R-70	3.1.1-004	A, 2
36225	Reactor Vessel External Surfaces and External Attachments	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-409	3.1.1-113	A
38507	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cracking	BWR Vessel ID Attachment Welds (B.2.1.4)	IV.A1.R-64	3.1.1-094	A
48507	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-64	3.1.1-094	B
38506	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
38508	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
38510	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel ID Attachment Welds (B.2.1.4)	IV.A1.R-64	3.1.1-094	A
48510	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-64	3.1.1-094	B
38509	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
38511	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38085	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel ID Attachment Welds (B.2.1.4)	IV.A1.R-64	3.1.1-094	A
48085	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.A1.R-64	3.1.1-094	B
38084	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
38086	Reactor Vessel Internal Attachments	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36408	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Nickel Alloy	Reactor Coolant	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
46408	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Nickel Alloy	Reactor Coolant	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
36410	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Nickel Alloy	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36411	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Nickel Alloy	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36414	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
36415	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36409	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
46409	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
36412	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36413	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36489	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
46489	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
36490	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36491	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36495	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	D
36496	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36492	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cracking	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1.1-098	A
46492	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cracking	Water Chemistry (B.2.1.2)	IV.A1.RP-369	3.1.1-098	B
36493	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cumulative Fatigue Damage	TLAA	IV.A1.R-04	3.1.1-007	A, 2
36494	Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1.1-085	B
36818	Reactor Vessel: shell and associated welds in the beltline region of the vessel	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	Neutron Fluence Monitoring (B.3.1.2)	IV.A1.RP-227	3.1.1-014	A
46818	Reactor Vessel: shell and associated welds in the beltline region of the vessel	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	Reactor Vessel Material Surveillance (B.2.1.19)	IV.A1.RP-227	3.1.1-014	A
56818	Reactor Vessel: shell and associated welds in the beltline region of the vessel	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	TLAA	IV.A1.R-62	3.1.1-013	A, 3

Table 3.1.2-3 Reactor Pressure Vessel Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. During power operation the insulated reactor vessel, nozzles, and safe end components have external temperature greater than 212 degrees F and are at a higher temperature than the air-indoor (uncontrolled) environment. During plant shutdown the containment atmosphere is normally above the dewpoint temperature. Therefore, wetting due to condensation and moisture accumulation will not occur during power operation or plant outages and loss of material due to general corrosion does not apply.
2. The TLAA designation in the Aging Management Programs column indicates that cumulative fatigue damage due to fatigue for this component is evaluated in Section 4.3.
3. The TLAA designation in the Aging Management Program column indicates loss of fracture toughness due to neutron embrittlement of this component is evaluated in Section 4.2.
4. The TLAA designation in the Aging Management Programs column indicates that cracking due to fatigue for this component is evaluated in Section 4.7.

Table 3.1.2-4 Reactor Pressure Vessel Instrumentation System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37075	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1.1-063	B
37076	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1.1-067	B
37114	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37115	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37116	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37081	Reactor Vessel Flange Leak Detection Line	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1.1-016	B
37080	Reactor Vessel Flange Leak Detection Line	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37083	Reactor Vessel Flange Leak Detection Line	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
37082	Reactor Vessel Flange Leak Detection Line	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
38104	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
38105	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
38102	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
37110	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37111	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1.1-136	B
37113	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.1.2-4 Reactor Pressure Vessel Instrumentation System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

None.

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36397	Control Rod Drive Guide Tube	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	A
46397	Control Rod Drive Guide Tube	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
36398	Control Rod Drive Guide Tube	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
36399	Control Rod Drive Guide Tube	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46399	Control Rod Drive Guide Tube	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36400	Control Rod Drive Guide Tube Base	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	A
46400	Control Rod Drive Guide Tube Base	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
36424	Control Rod Drive Guide Tube Base	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
39241	Control Rod Drive Guide Tube Base	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.R-416	3.1.1-099	A
36425	Control Rod Drive Guide Tube Base	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
46425	Control Rod Drive Guide Tube Base	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36426	Core Plate DP/SLC Line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1.1-103	C
46426	Core Plate DP/SLC Line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1.1-103	D
38716	Core Plate DP/SLC Line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
36427	Core Plate DP/SLC Line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46427	Core Plate DP/SLC Line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36440	Core plate, core plate bolts, core plate wedges, core plate incore guide tube plugs	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-93	3.1.1-103	A
46440	Core plate, core plate bolts, core plate wedges, core plate incore guide tube plugs	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-93	3.1.1-103	B
36443	Core plate, core plate bolts, core plate wedges, core plate incore guide tube plugs	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46443	Core plate, core plate bolts, core plate wedges, core plate incore guide tube plugs	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
38717	Core plate, core plate bolts, core plate wedges, core plate incore guide tube plugs	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Preload	BWR Vessel Internals (B.2.1.7)	IV.B1.R-420	3.1.1-120	A
36432	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-96	3.1.1-103	A

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
46432	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-96	3.1.1-103	B
36433	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
36431	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46431	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
39048	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Preload	TLAA			F, 3
36428	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-92	3.1.1-103	A
46428	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-92	3.1.1-103	B
36429	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
36430	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46430	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38738	Core Shroud (upper, central, lower) & shroud repair hardware	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Preload	BWR Vessel Internals (B.2.1.7)	IV.B1.R-420	3.1.1-120	C
36459	Core Shroud Support Structure (shroud support cylinder, shroud support plate)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-96	3.1.1-103	A
46459	Core Shroud Support Structure (shroud support cylinder, shroud support plate)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-96	3.1.1-103	B
36460	Core Shroud Support Structure (shroud support cylinder, shroud support plate)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
36462	Core Shroud Support Structure (shroud support cylinder, shroud support plate)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46462	Core Shroud Support Structure (shroud support cylinder, shroud support plate)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
38137	Core Spray Sparger Nozzle Elbows	Spray	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	A
48137	Core Spray Sparger Nozzle Elbows	Spray	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
38139	Core Spray Sparger Nozzle Elbows	Spray	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.R-417	3.1.1-099	A
38140	Core Spray Sparger Nozzle Elbows	Spray	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	A
48140	Core Spray Sparger Nozzle Elbows	Spray	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36434	Core Spray: Piping, spargers, and supports	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	A
46434	Core Spray: Piping, spargers, and supports	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	B
36435	Core Spray: Piping, spargers, and supports	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
36436	Core Spray: Piping, spargers, and supports	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46436	Core Spray: Piping, spargers, and supports	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36437	Core Spray: Piping, spargers, and supports	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1.1-103	A
46437	Core Spray: Piping, spargers, and supports	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1.1-103	B
36438	Core Spray: Piping, spargers, and supports	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	TLAA	IV.B1.R-53	3.1.1-003	A, 1
36439	Core Spray: Piping, spargers, and supports	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46439	Core Spray: Piping, spargers, and supports	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36447	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	A
46447	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
36449	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-220	3.1.1-099	A
36450	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
46450	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36452	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	A
46452	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	B
36454	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46454	Fuel Supports and Control Rod Drive Assemblies: Orificed Fuel Support	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36455	Instrumentation: Intermediate range monitor (IRM) dry tubes, source range monitor (SRM) dry tubes; incore neutron flux monitor guide tubes	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Gas (Internal)	None	None	IV.E.RP-07	3.1.1-107	C
36456	Instrumentation: Intermediate range monitor (IRM) dry tubes, source range monitor (SRM) dry tubes; incore neutron flux monitor guide tubes	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-105	3.1.1-103	A
46456	Instrumentation: Intermediate range monitor (IRM) dry tubes, source range monitor (SRM) dry tubes; incore neutron flux monitor guide tubes	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-105	3.1.1-103	B
36458	Instrumentation: Intermediate range monitor (IRM) dry tubes, source range monitor (SRM) dry tubes; incore neutron flux monitor guide tubes	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46458	Instrumentation: Intermediate range monitor (IRM) dry tubes, source range monitor (SRM) dry tubes; incore neutron flux monitor guide tubes	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
36464	Steam Dryers and Bolted/Welded Clamp Repairs	Structural Support	Stainless Steel	Reactor Coolant	Cracking, SCC/IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1.1-102	C
46464	Steam Dryers and Bolted/Welded Clamp Repairs	Structural Support	Stainless Steel	Reactor Coolant	Cracking, SCC/IGSCC	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1.1-102	D
36463	Steam Dryers and Bolted/Welded Clamp Repairs	Structural Support	Stainless Steel	Reactor Coolant	Cracking/Flow Induced Vibration	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-155	3.1.1-101	A

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36465	Steam Dryers and Bolted/Welded Clamp Repairs	Structural Support	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46465	Steam Dryers and Bolted/Welded Clamp Repairs	Structural Support	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B
38718	Steam Dryers and Bolted/Welded Clamp Repairs	Structural Support	Stainless Steel	Reactor Coolant	Loss of Preload	BWR Vessel Internals (B.2.1.7)	IV.B1.R-420	3.1.1-120	C
36466	Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.1.7)	IV.B1.R-98	3.1.1-103	A
46466	Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.1.2)	IV.B1.R-98	3.1.1-103	B
36468	Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1.1-043	E, 2
46468	Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Material	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1.1-043	B

Table 3.1.2-5 Reactor Pressure Vessel Internals Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.
2. The BWR Vessel Internals (B.2.1.7) program is substituted to manage the aging effects applicable to this component type, material, and environment combination.
3. The TLAA designation in the Aging Management Program column indicates that loss of preload of this component is evaluated in Section 4.2.

Table 3.1.2-6 Reactor Recirculation System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38999	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
39000	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
37821	Heat Exchanger – (R.R.P.M.G Set) Shell Side Components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	C
37820	Heat Exchanger – (R.R.P.M.G Set) Shell Side Components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-76	3.2.1-050	C
37888	Heat Exchanger – (R.R.P.M.G Set) Tube Side Components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	C
37887	Heat Exchanger – (R.R.P.M.G Set) Tube Side Components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-94	3.2.1-032	A
37507	Heat Exchanger – (Recirculation Pump Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	D
37508	Heat Exchanger – (Recirculation Pump Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	D
37509	Heat Exchanger – (Recirculation Pump Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
37952	Heat Exchanger – (Recirculation Pump Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37511	Heat Exchanger – (Recirculation Pump Cooler) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3.1-044	A
37512	Heat Exchanger – (Recirculation Pump Cooler) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-93	3.2.1-031	A
37513	Heat Exchanger – (Recirculation Pump Cooler) Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant (External)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
37514	Heat Exchanger – (Recirculation Pump Cooler) Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37525	Heat Exchanger – (Recirculation Pump Motor) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-94	3.2.1-032	A
37515	Heat Exchanger – (Recirculation Pump Motor) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-76	3.2.1-050	C
37540	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37541	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B

Table 3.1.2-6 Reactor Recirculation System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39051	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
37542	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37535	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37536	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
37537	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
38006	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
38005	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
38004	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
37552	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37553	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
37551	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
38002	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
38003	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
38000	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
37557	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37558	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
37556	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.1.2-6 Reactor Recirculation System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

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 System (2.3.2.1)
- Core Spray System (2.3.2.2)
- Emergency Cooling System (2.3.2.3)

3.2.2 RESULTS

The following tables summarize the results of the aging management review for Engineered Safety Features.

Table 3.2.2-1 Containment Spray System - Summary of Aging Management Evaluation

Table 3.2.2-2 Core Spray System - Summary of Aging Management Evaluation

Table 3.2.2-3 Emergency Cooling System - Summary of Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.2.2.1.1 Containment Spray System

Materials

The materials of construction for the Containment Spray System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with less than 15% Zinc
- Galvanized Steel
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The Containment Spray System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Concrete
- Condensation
- Lubricating Oil
- Raw Water
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Containment Spray System components require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Spray System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.2.2.1.2 Core Spray System

Materials

The materials of construction for the Core Spray System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with less than 15% Zinc
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The Core Spray System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Concrete
- Condensation
- Lubricating Oil
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Core Spray System components require management:

- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Core Spray System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.2.2.1.3 Emergency Cooling System

Materials

The materials of construction for the Emergency Cooling System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Glass
- Stainless Steel

Environments

The Emergency Cooling System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Condensation
- Treated Water
- Treated Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Emergency Cooling System components require management:

- Cracking

- Cumulative Fatigue Damage
- Long-Term Loss of Material
- 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 Emergency Cooling System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- TLAA
- Water Chemistry (B.2.1.2)

3.2.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 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 programs are addressed in the following subsections.

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.

Table 3.2.1 Item Number 3.2.1-001: This item evaluates stainless steel and carbon steel piping, piping components exposed to any environment for cumulative fatigue damage due to fatigue. Cumulative fatigue damage of carbon steel and stainless steel piping, piping components is managed as a TLAA for the Core Spray, Emergency Cooling, Condenser Air Removal and Off-Gas, and Feedwater/High Pressure Coolant Injection Systems as discussed in Section 4.3.

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 SS and nickel-alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) 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 into 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 that 3.2-3 requires management for SS and nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion, and (ii) 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 in the presence 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 SSCs, the following AMPs describe acceptable programs to manage loss of material due to pitting or 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, 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 mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive or corrosive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain moisture or 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.

Table 3.2.1 Item Number 3.2.1-004 and Item Number 3.2.1-048: These items evaluate loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components, and tanks exposed to air or condensation environments. There are no nickel alloy piping, piping components, or tanks exposed to the air or condensation environments in the Engineered Safety Features. Plant-specific operating experience (OE) from 2016 to 2026 associated with stainless steel components in the Engineered Safety Features and Reactor Vessel, Internals, and Reactor Coolant System has been evaluated to determine if prolonged exposure to the environments of air-indoor, uncontrolled and condensation has resulted in loss of material. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking is not occurring in stainless steel components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.2.1 Item Number 3.2.1-099: Not applicable. There are no stainless steel, nickel alloy tanks exposed to air, or condensation in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-106: Not applicable. There are no stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, or condensation in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-107: Not applicable. There are no insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, or condensation in Engineered Safety Features

Table 3.2.1 Item Number 3.2.1-112: Not applicable. There are no stainless steel, nickel alloy underground piping, piping components, or tanks in Engineered Safety Features

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 remains 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: (i) the applicant identifies those portions of the system that are normally dry but subject to periodic wetting; (ii) plant-specific procedures exist to drain the normally dry portions that have been wetted during normal plant operation or inadvertently; (iii) the plant-specific configuration of the drains and piping allow sufficient draining to empty the normally dry pipe; (iv) plant-specific OE has not revealed loss of material or flow blockage due to fouling; and (v) 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.

Table 3.2.1 Item Number 3.2.1-006: This item evaluates loss of material due to general, pitting, and crevice corrosion and flow blockage due to fouling of metallic drywell and suppression chamber spray nozzles and flow orifices exposed to air-indoor uncontrolled and condensation internal environments. There are no flow orifices exposed to air – indoor uncontrolled or condensation (internal) environments in Engineered Safety Features. There are no spray nozzles exposed to air-indoor uncontrolled (internal) environments in Engineered Safety Features.

The spray nozzles within the NMP1 Containment Spray System are stainless steel and are exposed to a condensation internal environment. The Containment Spray System carbon steel piping sections downstream of the inboard primary containment motor operated isolation valves up to the drywell and suppression chamber spray nozzles are normally dry and subject to wetting, but are periodically wetted only during transient or accident conditions that require drywell or suppression chamber spray operation. Since the upstream piping is carbon steel, flow blockage due to fouling is an applicable aging effect for the spray nozzles.

When the piping between the drywell spray inboard and outboard primary containment isolation valves is filled with water to support in-service testing of valves, that piping is drained prior to opening the inboard isolation valve to preclude water flow into the downstream piping towards the spray header, and to maintain the piping between the isolation valves and the downstream piping to the spray header dry. During in-service testing of the primary containment isolation valves associated with the suppression chamber spray, the piping configuration and sequence of valve testing precludes the piping downstream of the inboard primary containment isolation valve from being wetted. When the piping between the suppression chamber spray inboard and outboard primary containment isolation valves is filled with water to support in-service testing of pumps and valves, any leakage past the inboard primary containment isolation valve during

testing drains to the suppression chamber via the spray nozzles due to the piping configuration to maintain the piping downstream of the inboard isolation valve dry.

The spray nozzles within the Fire Detection and Protection System composed of copper alloy with 15 percent zinc or more are normally exposed to a condensation internal environment. They are exposed to gaseous carbon dioxide upon system initiation.

Plant-specific OE from 2016 to 2026 has not revealed loss of material or flow blockage due to fouling of fire protection carbon dioxide, drywell, or suppression chamber spray nozzles. Additionally, tests to verify the drywell and torus spray nozzles are free from obstructions are performed as needed in accordance with Technical Specifications. Therefore, the One-Time Inspection (B.2.1.20) program will be implemented to manage the aging effect of flow blockage due to fouling for the drywell and suppression chamber spray nozzles. The Fire Protection (B.2.1.15) program will be utilized to manage loss of material for the carbon dioxide spray nozzles. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) and Fire Protection (B.2.1.15) programs are described in Appendix B.

3.2.2.2.4 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: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components, or (iv) 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 to leach onto the component surface or into the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion compromising 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. The SCC in SS components is not an aging effect that requires management if: (i) plant-specific OE does not reveal a history of SCC and (ii) 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 due to the presence 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, "OneTime Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable

programs to manage cracking due to SCC: (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. 3.2-5

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. 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.

Table 3.2.1 Item Number 3.2.1-007: This item evaluates cracking due to stress corrosion cracking (SCC) in stainless steel piping, piping components, and tanks exposed to air and condensation environments. Plant-specific OE from 2016 to 2026 associated with stainless steel and cast austenitic stainless steel (CASS) components in the Engineered Safety Features, Reactor Vessel, Internals, and Reactor Coolant System has been evaluated to determine if prolonged exposure to the environments of air-indoor, uncontrolled and condensation has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel and CASS in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking is not occurring in stainless steel and CASS components exposed to air-indoor, uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.2.1 Item Number 3.2.1-080: Not applicable. There are no stainless steel underground piping, piping components or tanks in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-103: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-108: Not applicable. There are no insulated stainless steel piping, piping components, tanks exposed to air or condensation in Engineered Safety Features.

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 Section B.1.3

3.2.2.2.6 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.6 and Appendix B, Section B.1.4.

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: (i) a 10 year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (ii) a 5 year search of plant-specific OE revealing that 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 any recurring aging effect(s) are adequately managed. 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: (i) 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, (ii) the basis for the adequacy of augmented or lack of augmented inspections, (iii) the trend of which parameters will be followed 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), (iv) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (v) 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° 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 was 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 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 environments other than raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Table 3.2.1 Item Number 3.2.1-066: Not applicable. There are no metallic piping, piping components, tanks exposed to raw water, and waste water with the aging effect/mechanism of loss of material due to recurring internal corrosion in Engineered Safety Features.

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 SLR, acceptance criteria for this further evaluation are provided for demonstrating that the specific material is not susceptible to SCC or the ambient environment is not aggressive in nature. Cracking due to SCC is an aging effect which requires management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

3.2.2.2.8.1 Susceptible Material

If the material is not susceptible to SCC, then cracking is not an aging effect which requires management. The microstructure of an aluminum alloy, of which alloy composition is only one factor that 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 type, 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 as fabricated (F), solution heat-treated (W), annealed (O)x, thermally treated (T)3x, T4x, or T6x temper
- 5xxx series alloys with a magnesium content of 3.5 weight percent (wt%) 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 wt%

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, 6063-T6, and 5454-x, 3.2-7 respectively. 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, and product form. For tempers not addressed above, the basis used to determine that the alloy is not susceptible and technical information substantiating the basis is added to the SLRA.

3.2.2.2.8.2 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 which requires management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys include the presence of 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 layer or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, halide concentrations sufficient 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. The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. 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.

Table 3.2.1 Item Number 3.2.1-100: This item evaluates cracking due to SCC in aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water, and waste water. There are no aluminum alloy piping, piping components, tanks exposed to air (internal), raw water, or waste water in Engineered Safety Features.

Plant-specific OE from 2016 to 2026 associated with the aluminum components in the Engineered Safety Features has been evaluated to determine if prolonged exposure to the environment of condensation has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external

surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking.

The following component types in the identified systems are exposed to condensation (internal) but are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required.

- Emergency Cooling System Tanks (Emergency Condenser Make-Up Water Tanks): Components are constructed of a 5052-H34 aluminum alloy.

Table 3.2.1 Item Number 3.2.1-101: This item evaluates cracking due to SCC in aluminum piping, piping components, tanks exposed to air, and condensation (external). There are no aluminum piping, piping components, or tanks exposed to condensation (external) in the Engineered Safety Features.

Plant-specific OE from 2016 to 2026 associated with the aluminum components in the Engineered Safety Features has been evaluated to determine if prolonged exposure to the environment of air-indoor, uncontrolled has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking.

The following component types in the identified systems are exposed to air-indoor uncontrolled but are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required.

- Emergency Cooling System Piping, Piping components: Components are constructed of a 3xxx series aluminum alloy.
- Emergency Cooling System Valve Bodies: Components are constructed of aluminum 6061-T6.
- Emergency Cooling System Tanks (Emergency Condenser Make Up Water Tanks): Components are constructed of a 5052-H34 aluminum alloy.

Table 3.2.1 Item Number 3.2.1-102: Not applicable. There are no 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 Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-109: Not applicable. There are no insulated aluminum piping, piping components, or tanks exposed to air or condensation in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-110: Not applicable. There are no aluminum underground piping, piping components, or tanks in Engineered Safety Features.

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 highly alkaline 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 highly alkaline 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 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 penetrate 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: (i) attributes of the concrete are consistent with ACI 318 (ACI 1997-TN8116) or ACI 349 (ACI 1985-TN8165) (low water to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557 (NRC 1996-TN8063); (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) 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.

Table 3.2.1 Item Number 3.2.1-055 – This item evaluates steel piping, piping components exposed to concrete. The Containment Spray Pump Suction Tanks and Core Spray Pump Suction Tanks are constructed of carbon steel and exposed to concrete. The reinforced concrete surrounding the tanks was designed to ACI 318. Plant-specific OE indicates no degradation of the concrete around these tanks. The tanks are located at elevation 198' and are not potentially exposed to groundwater.

Table 3.2.1 Item Number 3.2.1-091 – Not applicable. There are no stainless steel piping, piping components exposed to concrete in Engineered Safety Features.

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 greatly depends on the 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 that requires management for aluminum alloys if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) a one-time inspection 3.2-9 demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. Alternatively, loss of material due to pitting and crevice corrosion need not be managed if the type of aluminum is not susceptible to cracking and plant specific OE does not reveal any issues related to loss of material due to pitting or crevice corrosion. 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 in the presence 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. The 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 a 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. The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. 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," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Table 3.2.1 Item Number 3.2.1-042 and Item Number 3.2.1-056: These items evaluate loss of material due to pitting, crevice corrosion in aluminum piping, piping components, and tanks exposed to air and condensation. There are no aluminum piping, piping components, tanks exposed to air – indoor, uncontrolled (internal) or condensation (external) in the Engineered Safety Features.

Plant-specific OE from 2016 to 2026 associated with aluminum alloy components in the Engineered Safety Features has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation (internal) has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material.

The following component types in the identified systems are exposed to air and condensation but are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required. As the components are not susceptible to cracking and plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion, loss of material due to pitting and crevice corrosion need not be managed.

- Emergency Cooling System Piping, Piping components: Components are constructed of a 3xxx series aluminum.
- Emergency Cooling System Valve Bodies: Components are constructed of aluminum 6061-T6.
- Emergency Cooling System Tanks (Emergency Condenser Make Up Water Tanks): Components are constructed of a 5052-H34 aluminum alloy.

Table 3.2.1 Item Number 3.2.1-105: Not applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, or condensation in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-111: Not applicable. There are no aluminum underground piping, piping components, or tanks in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-119: Not applicable. There are no insulated aluminum piping, piping components, tanks exposed to air, or condensation in Engineered Safety Features.

Table 3.2.1 Item Number 3.2.1-121: Not applicable. There are no aluminum piping, piping components, tanks exposed to raw water, or waste water in Engineered Safety Features.

3.2.2.2.11 Loss of Material Due to Wear

Industry OE indicates that significant loss of material due to wear can occur in ASME Code Class 2, small-bore piping. For example, loss of material can occur in the presence

of RMI and flow-induced vibrations of ASME Code Class 2 small-bore piping. This type of wear is difficult to identify unless the insulation is removed and the OD of the piping is visually examined for wear marks (NRC 2020-TN8034). This type of wear is called OD pipe wear, and in some instances can be potentially near 360° around the OD of the subject pipe and could significantly reduce the load-bearing capacity of the subject pipe. Therefore, the applicant should perform a further evaluation to confirm the absence of the specific aging effect. If moderate or no degradation is evident, but it is determined that the insulation has the potential to cause wear, the applicant may choose to mitigate the loss of material due to wear or alternatively use an existing program for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. The reviewer should ensure that the applicant has verified through inspections that OD pipe wear is not an applicable aging effect that needs to be monitored or provide for periodic inspection program so that significant OD loss of material is detected prior to loss of intended function.

Table 3.2.1 Item Number 3.2.1-135: Not applicable. There are no steel, stainless steel or nickel-alloy ASME Code Class 2 small bore piping, and piping components with reflective metal insulation exposed to air in Engineered Safety Features.

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Engineered Safety Features components:

- Section 4.3, Metal Fatigue Analyses
 - Section 4.3.2, Reactor Vessel and Piping Fatigue Analyses
 - Section 4.3.3, Fatigue of the Emergency Condensers
 - Section 4.3.4, ASME Section III, Class 2 and 3, and ANSI B31.1 Allowable Stress Analysis and HELB Exclusions of Recirculation Piping Analysis

3.2.3 **CONCLUSION**

The Engineered Safety Features piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Engineered Safety Features components are identified in the summaries in Section 3.2.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Engineered Safety Features components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-001	Stainless steel (SS), steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, Standard Review Plan for Review of Subsequent License Renewal (SRP-SLR) Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.2.2.1)	Fatigue is a TLAA; further evaluation is documented in Subsection 3.2.2.2.1.
3.2.1-002	This Item Number is not listed in NUREG-2192.				
3.2.1-003	This Item Number is not listed in NUREG-2192.				
3.2.1-004	SS, 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 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the stainless steel expansion joints, flow devices, heat exchanger components, piping, piping components, pump casings, spray nozzles, and valve bodies exposed to air - indoor, uncontrolled and condensation (external) in the Containment Spray System, Core Spray System, Emergency Cooling System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.2.2.2.2.
3.2.1-005	PWR Only				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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)	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program and will be used to manage flow blockage of the stainless steel spray nozzles exposed to condensation (internal) in the Containment Spray System. Consistent with NUREG-2191 with exceptions. The Fire Protection (B.2.1.15) program will be used to manage loss of material of copper alloy with 15% zinc or more spray nozzles exposed to condensation (internal) in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation and Fire Protection (B.2.1.15) program implementation. See Subsection 3.2.2.2.3.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-007	SS piping, piping components, tanks exposed to air, condensation	Cracking due to stress corrosion cracking (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 exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the CASS and stainless steel expansion joints, flow devices, flow devices (Class 1), heat exchanger components, piping, piping components, piping, piping components: Class 1 greater than or equal to 4" NPS, piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS, pump casings, spray nozzles, valve bodies, and valve bodies: Class 1 exposed to air - indoor, uncontrolled and condensation in the Containment Spray System, Core Spray System, Emergency Cooling System, Reactor Coolant Pressure Boundary System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.2.2.2.4.
3.2.1-008	PWR Only				
3.2.1-009	PWR Only				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-010	Cast austenitic stainless steel (CASS) 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	Consistent with NUREG-2191. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8) program will be used to manage loss of fracture toughness due to thermal aging embrittlement for CASS piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F) in the Reactor Water Cleanup System. Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will be used to manage loss of fracture toughness of the CASS valve bodies exposed to treated water > 482°F in the Reactor Water Cleanup System.
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	Consistent with NUREG-2191 with exceptions. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning / flow-accelerated corrosion of the carbon steel piping, piping components, piping, piping components: Class 1 greater than or equal to 4" NPS, piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS, and valve bodies: Class 1 exposed to treated water in the Emergency Cooling System and Reactor Coolant Pressure Boundary System. Exceptions apply to the NUREG-2191 recommendations for Flow-Accelerated Corrosion (B.2.1.9) program implementation.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-012	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to "SCC; cyclic loading"	AMP XI.M18, "Bolting Integrity"	No	Not Applicable. There are no high-strength steel closure bolting exposed to air, soil, underground in Engineered Safety Features.
3.2.1-013	This Item Number is not listed in NUREG-2192.				
3.2.1-014	SS, 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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel and stainless steel bolting exposed to air - indoor, uncontrolled in the Containment Spray System, Core Spray System, and Emergency Cooling System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of the carbon and low alloy steel and stainless steel bolting exposed to air - indoor, uncontrolled, air - indoor, uncontrolled, raw water, and treated water in the Containment Spray System, Core Spray System, and Emergency Cooling Systems. Exceptions apply to the NUREG-2191 recommendations for the Bolting Integrity (B.2.1.10) program implementation.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-016	Steel piping, piping components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, microbiologically induced corrosion (MIC)	AMP XI.M2, "Water Chemistry,"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel, cast iron, and galvanized steel heat exchanger components, piping, piping components: Class 1 greater than or equal to 4" NPS, piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS, pump casings, tanks, valve bodies, and valve bodies: Class 1 exposed to reactor coolant and treated water in the Containment Spray System, Core Spray System, Emergency Cooling System, Reactor Coolant Pressure Boundary System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program.
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,"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the aluminum alloy piping, piping components, and valve bodies exposed to treated water in the Emergency Cooling System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program.
3.2.1-018	This Item Number is not listed in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-019	Stainless steel, nickel-alloy heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry,"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage reduction of heat transfer of the stainless steel heat exchanger tubes exposed to treated water and treated water > 140°F in the Containment Spray System and Emergency Cooling System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program.
3.2.1-020	PWR Only				
3.2.1-021	This Item Number is not listed in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-022	Nickel alloy, SS 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,"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the CASS and stainless steel flow devices, flow devices (Class 1), heat exchanger components, piping, piping components, piping, piping components: Class 1 greater than or equal to 4" NPS, piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS, reactor vessel flange leak detection lines, strainers (element), valve bodies, and valve bodies: Class 1 exposed to reactor coolant, treated water, treated water > 140°F, and treated water > 200°F in the Containment Spray System, Core Spray System, Emergency Cooling System, Reactor Coolant Pressure Boundary System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program.
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	Consistent with NUREG-2191 with exceptions. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the carbon steel and cast iron heat exchanger components, piping, piping components, pump casings, and valve bodies exposed to raw water in the Containment Spray System. Exceptions apply to the NUREG-2191 recommendations for the Open-Cycle Cooling Water System (B.2.1.11) program.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-024	PWR Only				
3.2.1-025	SS 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	Consistent with NUREG-2191 with exceptions. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the stainless steel heat exchanger components exposed to raw water in the Containment Spray System. Exceptions apply to the NUREG-2191 recommendations for the Open-Cycle Cooling Water System (B.2.1.11) program.
3.2.1-026	This Item Number is not listed in NUREG-2192.				
3.2.1-027	SS, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191 with exceptions. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage reduction of heat transfer of the stainless steel heat exchanger tubes exposed to raw water in the Containment Spray System. Exceptions apply to the NUREG-2191 recommendations for the Open-Cycle Cooling Water System (B.2.1.11) program.
3.2.1-028	SS piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-029	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no steel piping, piping components exposed to closed-cycle cooling water in Engineered Safety Features.
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	Not Applicable. There are no steel heat exchanger components exposed to closed-cycle cooling water in Engineered Safety Features.
3.2.1-031	SS 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. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the stainless steel heat exchanger components exposed to closed cycle cooling water > 140°F in the Reactor Recirculation System.
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	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the copper alloy with less than 15% zinc heat exchanger components exposed to closed cycle cooling water in the Reactor Recirculation System.
3.2.1-033	Copper alloy, SS heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-034	Copper alloy (>15% zinc or >8% aluminum) 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	Consistent with NUREG-2191 with exceptions. Loss of material due to selective leaching of heat exchanger tubes fabricated from admiralty brass (inhibited brass) and exposed to closed cycle cooling water is not an applicable aging effect requiring management consistent with NUREG-2191 Table IX.C for inhibited brass. Heat exchanger tubes fabricated from inhibited brass are identified through plant specific notes provided in the applicable SLRA Table 3.3.2-x for the Radioactive Waste System. There are no copper alloy (>15% zinc or >8% aluminum) piping, piping components, heat exchanger components exposed to closed cycle cooling water or treated water in the Engineered Safety Features. Exceptions apply to the NUREG-2191 recommendations for Selective Leaching (B.2.1.21) program implementation.
3.2.1-035	PWR Only				
3.2.1-036	PWR Only				
3.2.1-037	Gray cast iron, ductile iron, malleable iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no gray cast iron, ductile iron, malleable iron piping, piping components exposed to soil in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-038	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no elastomer piping, piping components, seals exposed to air, condensation in Engineered Safety Features.
3.2.1-039	This Item Number is not listed in NUREG-2192.				
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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon steel and cast iron heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to air - indoor, uncontrolled in the Containment Spray System, Core Spray System, Emergency Cooling System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System.
3.2.1-041	This Item Number is not listed in NUREG-2192.				
3.2.1-042	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Consistent with NUREG-2191. No aging management program is required. See Subsection 3.2.2.2.10.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no elastomer piping, piping components, seals exposed to air, condensation in Engineered Safety Features.
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	Not Applicable. There are no steel piping, piping components, ducting, ducting components exposed to air – indoor uncontrolled in Engineered Safety Features.
3.2.1-045	PWR Only				
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel heat exchanger components, piping, piping components, tanks, and valve bodies exposed to condensation in the Core Spray System and Emergency Cooling System.
3.2.1-047	PWR Only				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-048	SS, 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 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the stainless steel spray nozzles and expansion joints exposed to condensation (internal) in the Containment Spray System and Emergency Cooling System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 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,"	No	Not Applicable. There are no steel piping, piping components exposed to lubricating oil in Engineered Safety Features.
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,"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the copper alloy with less than 15% zinc heat exchanger components exposed to lubricating oil in the Containment Spray System, Core Spray System, and Reactor Recirculation System.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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,"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage reduction of heat transfer of the copper alloy with less than 15% zinc heat exchanger tubes exposed to lubricating oil in the Containment Spray System, Core Spray System, and Feedwater/High Pressure Coolant Injection System.
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. There are no steel piping, piping components exposed to soil, concrete, underground in Engineered Safety Features.
3.2.1-053	SS, nickel alloy piping, piping components, tanks, exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete in Engineered Safety Features.
3.2.1-053a	This Item Number is not listed in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-054	SS, nickel alloy piping, piping components ≥ 4 nominal pipe size exposed to treated water $> 93^{\circ}\text{C}$ ($> 200^{\circ}\text{F}$)	Cracking due to SCC, intergranular stress corrosion cracking (IGSCC)	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel piping, piping components: Class 1 greater than or equal to 4" NPS and valve bodies: Class 1 exposed to treated water $> 200^{\circ}\text{F}$ in the Reactor Coolant Pressure Boundary System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program.
3.2.1-055	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Consistent with NUREG-2191. See Subsection 3.2.2.2.9.
3.2.1-056	Aluminum piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP-XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Consistent with NUREG-2191 with exceptions. No aging management program is required. See Subsection 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.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-058	PWR Only				
3.2.1-059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Consistent with NUREG-2191.
3.2.1-060	Glass piping elements exposed to air, underground, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191.
3.2.1-061	This Item Number is not listed in NUREG-2192.				
3.2.1-062	Nickel-alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel-alloy piping, piping components exposed to air with borated water leakage in the Engineered Safety Features.
3.2.1-063	SS piping, piping components exposed to air with borated water leakage, gas	None	None	No	Not Applicable. There are no stainless steel piping, piping components exposed to air with borated water leakage, gas in the Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not Applicable. There are no steel piping, piping components exposed to air – indoor controlled, gas in the Engineered Safety Features.
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. There are no metallic piping, piping components exposed to treated water, treated borated water with the aging effect/mechanism of wall thinning due to erosion in Engineered Safety Features.
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. There are no metallic piping, piping components, tanks exposed to raw water, waste water with the aging effect/mechanism of loss of material due to recurring internal corrosion in Engineered Safety Features. See Subsection 3.2.2.2.7.
3.2.1-067	SS tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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. There are no steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation in Engineered Safety Features.
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. There are no insulated steel piping, piping components, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in Engineered Safety Features.
3.2.1-070	Steel, SS, 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	Not Applicable. There are no 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 in Engineered Safety Features.
3.2.1-071	Insulated copper alloy (>15% zinc or >8% aluminum) piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no insulated copper alloy (>15% zinc or >8% aluminum) piping, piping components, tanks exposed to air, condensation in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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, lubricating oil, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program will be used to manage loss of coating or lining integrity of the carbon steel (with Internal Coatings) ducting and components, tanks exposed to condensation in the City Water System, Compressed Air Systems, Condensate and Condensate Transfer System, Makeup Demineralizer System, Reactor Water Cleanup, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System and Turbine Building HVAC System. Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of coating or lining integrity of the carbon steel (with internal coatings) tanks exposed to condensation in the Makeup Demineralizer, Reactor Water Cleanup, and Condensate and Condensate Transfer Systems. Exceptions apply to the NUREG-2191 recommendations for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-073	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program will be used to manage loss of material of the carbon steel (with internal coatings) ducting and components, tanks, exposed to condensation in the City Water System, Compressed Air Systems, Makeup Demineralizer System, Radioactive Waste System, Reactor Water Cleanup, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, and Condensate and Condensate Transfer System. Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel (with internal coatings) tanks exposed to condensation in the Makeup Demineralizer, Reactor Water Cleanup, and Condensate and Condensate Transfer Systems. Exceptions apply to the NUREG-2191 recommendations for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-074	Gray cast iron, ductile iron, malleable iron piping, piping components with internal coatings/linings exposed to closed cycle cooling water, raw water, treated water, treated borated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not Applicable. There are no gray cast iron, ductile iron, malleable iron piping, piping components with internal coatings/linings exposed to closed cycle cooling water, raw water, treated water, treated borated water, waste water in Engineered Safety Features.
3.2.1-075	This Item Number is not listed in NUREG-2192.				
3.2.1-076	SS, 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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel bolting and stainless steel bolting, bolting (closure) exposed to raw water and treated water in the Containment Spray System and Core Spray System. Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program will be used to manage loss of material of the stainless steel bolting exposed to treated water in the Cranes, Hoists, and Refueling Equipment System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.2.1-077	This Item Number is not listed in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-078	SS, 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 Used. There are no stainless steel, steel, aluminum piping, piping components, tanks exposed to soil in Engineered Safety Features. Cracking due to SCC in carbon steel components exposed to concrete is addressed by Item Number 3.2.1-055.
3.2.1-079	SS closure bolting exposed to air, soil, concrete, underground	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage cracking of the stainless steel bolting, bolting (closure) exposed to air - indoor, uncontrolled in the Containment Spray System and Core Spray System. Exceptions apply to the NUREG-2191 recommendations for the Bolting Integrity (B.2.1.10) program implementation.
3.2.1-080	SS 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. There are no stainless steel underground piping, piping components, tanks in Engineered Safety Features. See Subsection 3.2.2.2.4.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-081	SS, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation in Engineered Safety Features.
3.2.1-082	This Item Number is not listed in NUREG-2192.				
3.2.1-083	This Item Number is not listed in NUREG-2192.				
3.2.1-084	This Item Number is not listed in NUREG-2192.				
3.2.1-085	This Item Number is not listed in NUREG-2192.				
3.2.1-086	This Item Number is not listed in NUREG-2192.				
3.2.1-087	Nonmetallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no nonmetallic thermal insulation exposed to air, condensation in Engineered Safety Features.
3.2.1-088	This Item Number is not listed in NUREG-2192.				
3.2.1-089	This Item Number is not listed in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-090	Steel components exposed to treated water, treated borated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, "One Time Inspection"	No	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage long-term loss of material of the carbon steel, cast iron, and galvanized steel heat exchanger components, piping, piping components, pump casings, tanks and valve bodies exposed to raw water and treated water in the Containment Spray System, Core Spray System, Emergency Cooling System, Reactor Pressure Vessel Instrumentation System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation.
3.2.1-091	SS piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not Applicable. There are no stainless steel piping, piping components exposed to concrete in the Engineered Safety Features. See Subsection 3.2.2.2.9.
3.2.1-092	This Item Number is not listed in NUREG-2192.				
3.2.1-093	This Item Number is not listed in NUREG-2192.				
3.2.1-094	This Item Number is not listed in NUREG-2192.				
3.2.1-095	This Item Number is not listed in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-096	Steel, SS piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel, stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in Engineered Safety Features.
3.2.1-097	This Item Number is not listed in NUREG-2192.				
3.2.1-098	Copper alloy (>15% zinc or >8% aluminum) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no copper alloy (>15% zinc or >8% aluminum) piping, piping components exposed to soil in Engineered Safety Features.
3.2.1-099	SS, nickel-alloy tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Not Applicable. There are no stainless steel, nickel-alloy tanks exposed to air, condensation in Engineered Safety Features. See Subsection 3.2.2.2.2.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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)	Consistent with NUREG-2191. No aging management program required. See Subsection 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)	Consistent with NUREG-2191. No aging management program required. See Subsection 3.2.2.2.8.
3.2.1-102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not Applicable. There are no 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 in Engineered Safety Features. See Subsection 3.2.2.2.8.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-103	SS 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)	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in Engineered Safety Features. See Subsection 3.2.2.2.4.
3.2.1-104	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete in Engineered Safety Features.
3.2.1-105	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not Applicable. There are no Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in Engineered Safety Features. See Subsection 3.2.2.2.10.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-106	SS, 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)	Not Applicable. There are no stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in Engineered Safety Features. See Subsection 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)	Not Applicable. There are no insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation in Engineered Safety Features. See Subsection 3.2.2.2.2.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-108	Insulated SS 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)	Not Applicable. There are no insulated stainless steel piping, piping components, tanks exposed to air, condensation in Engineered Safety Features. See Subsection 3.2.2.2.4.
3.2.1-109	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not Applicable. There are no insulated aluminum piping, piping components, tanks exposed to air, condensation in Engineered Safety Features. See Subsection 3.2.2.2.8.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-110	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not Applicable. There are no aluminum underground piping, piping components, tanks in Engineered Safety Features. See Subsection 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. There are no aluminum underground piping, piping components, tanks in Engineered Safety Features. See Subsection 3.2.2.2.10.
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. There are no stainless steel, nickel-alloy underground piping, piping components, tanks in Engineered Safety Features. See Subsection 3.2.2.2.2.
3.2.1-113	This Item Number is not listed in NUREG-2192.				

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-114	SS, nickel-alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry,"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage cracking of the CASS and stainless steel flow devices (Class 1), heat exchanger components, piping, piping components, reactor vessel flange leak detection lines, valve bodies, and valve bodies: Class 1 exposed to treated water > 140°F in the Emergency Cooling System, Reactor Coolant Pressure Boundary System, and Reactor Pressure Vessel Instrumentation System. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program.
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,"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to treated water in Engineered Safety Features.
3.2.1-116	Titanium ([ASTM] Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not Applicable. There are no titanium ([ASTM] Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water in the Engineered Safety Features.
3.2.1-117	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to closed-cycle cooling water in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-118	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed cycle cooling water	None	None	No	Not Applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed cycle cooling water in the Engineered Safety Features.
3.2.1-119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not Applicable. There are no insulated aluminum piping, piping components, tanks exposed to air, condensation in Engineered Safety Features. See Subsection 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. There are no aluminum piping, piping components, tanks exposed to soil, concrete in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-121	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not Applicable. There are no aluminum piping, piping components, tanks exposed to raw water, waste water in Engineered Safety Features. See Subsection 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. There are no elastomer piping, piping components, seals exposed to air in Engineered Safety Features.
3.2.1-123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no elastomer piping, piping components, seals exposed to air in Engineered Safety Features.
3.2.1-124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, tanks exposed to air with borated water leakage in the Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. There are no steel closure bolting exposed to soil, concrete, underground in Engineered Safety Features.
3.2.1-126	Titanium, super austenitic piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to pitting, crevice corrosion, MIC (except for titanium; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no titanium, super austenitic piping, piping components, tanks, closure bolting exposed to soil, concrete, underground in Engineered Safety Features.
3.2.1-127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There are no copper alloy piping, piping components exposed to concrete in the Engineered Safety Features.
3.2.1-128	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no copper alloy piping, piping components exposed to soil, underground in Engineered Safety Features.
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	Not Applicable. There are no stainless steel tanks exposed to soil, concrete in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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,"	No	Not Applicable. There are no steel heat exchanger components exposed to lubricating oil in Engineered Safety Features.
3.2.1-131	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no aluminum piping, piping components exposed to raw water in Engineered Safety Features.
3.2.1-132	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in Engineered Safety Features.
3.2.1-133	Titanium piping, piping components, heat exchanger components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no titanium piping, piping components, heat exchanger components exposed to raw water in Engineered Safety Features.

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-134	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil in Engineered Safety Features.
3.2.1-135	Steel, stainless steel or nickel-alloy ASME Code Class 2 small bore piping, and piping components with reflective metal insulation exposed to air	Loss of material due to wear	Plant-specific or existing aging management program if loss of material is not mitigated	Yes (SRP-SLR Section 3.2.2.2.11)	Not Applicable. There are no steel, stainless steel or nickel-alloy ASME Code Class 2 small bore piping, and piping components with reflective metal insulation exposed to air in Engineered Safety Features.

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35288	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
35287	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
37121	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
37122	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
37119	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
37120	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Treated Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
36898	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	V.E.E-421	3.2.1-079	B
36896	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
36897	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
37995	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
37996	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
36894	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
36895	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
36907	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
36906	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
36905	Flow Device	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
36904	Flow Device	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
36908	Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36900	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
36899	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
36903	Flow Device	Throttle	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
36902	Flow Device	Throttle	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
36901	Flow Device	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35267	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
35269	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35271	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
35277	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.EP-91	3.2.1-025	A
35276	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.EP-91	3.2.1-025	A
35275	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35272	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36910	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.EP-90	3.2.1-023	A
37141	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36909	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.EP-90	3.2.1-023	A

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35260	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.E-21	3.2.1-027	A
35259	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tubes	Heat Transfer	Stainless Steel	Treated Water (External)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	V.D2.EP-74	3.2.1-019	B
35262	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.EP-91	3.2.1-025	A
35261	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.EP-91	3.2.1-025	A
35263	Heat Exchanger – (Containment Spray Raw Water Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37153	Heat Exchanger – (Containment Spray Raw Water Pump Motor Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-78	3.2.1-051	A
37154	Heat Exchanger – (Containment Spray Raw Water Pump Motor Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VIII.E.SP-56	3.4.1-022	A
37152	Heat Exchanger – (Containment Spray Raw Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-76	3.2.1-050	C
37156	Heat Exchanger – (Containment Spray Raw Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
37155	Heat Exchanger – (Containment Spray Raw Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
38210	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
38211	Piping elements	Leakage Boundary (Spatial)	Glass	Raw Water (Internal)	None	None	V.F.EP-28	3.2.1-060	A
35306	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
35308	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35307	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35323	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36919	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37142	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36918	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
36912	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36911	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35325	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35324	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35316	Piping, piping components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
35314	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
35312	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35313	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
35315	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
35317	Piping, piping components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
35321	Piping, piping components	Pressure Boundary	Galvanized Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35320	Piping, piping components	Pressure Boundary	Galvanized Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
38106	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36926	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36927	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36923	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36924	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36920	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36921	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36922	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-31	3.3.1-072	B
35223	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35224	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35225	Pump Casing (Containment Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-31	3.3.1-072	B
36932	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
37145	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Carbon Steel	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36933	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Carbon Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
36934	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
37146	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36935	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
38095	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
38096	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
38097	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38114	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
38100	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
38098	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
38099	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
38101	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
36940	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
36939	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
36938	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
36937	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
36936	Pump Casing (Containment Spray Raw Water Pumps)	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
36942	Spray Nozzles	Spray	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
36941	Spray Nozzles	Spray	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
37147	Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
36944	Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Flow Blockage	One-Time Inspection (B.2.1.20)	V.D2.EP-113a	3.2.1-006	B
36943	Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-61b	3.2.1-048	B
35295	Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
35294	Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37123	Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			H, 1
35293	Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
36946	Tanks (Containment Spray Pump Suction Tank)	Pressure Boundary	Carbon Steel	Concrete (External)	None	None	V.F.EP-112	3.2.1-055	A
38094	Tanks (Containment Spray Pump Suction Tank)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36945	Tanks (Containment Spray Pump Suction Tank)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35349	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
35351	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35350	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35353	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36948	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
37148	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36947	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	V.C.E-22	3.2.1-023	A
35355	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35354	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
37884	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37883	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
37882	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-1 Containment Spray System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage flow blockage/fouling of the stainless steel suction strainers.

Table 3.2.2-2 Core Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35601	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
35602	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
36044	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
36122	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Treated Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
36114	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	V.E.E-421	3.2.1-079	B
36107	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
36108	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
36115	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2.1-076	B
36116	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
36045	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
36046	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
36047	Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
36862	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
36863	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
36054	Flow Device	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
36200	Heat Exchanger – (Core Spray Pump Motor Coolers) Tube Side Components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	C
36197	Heat Exchanger – (Core Spray Pump Motor Coolers) Tube Side Components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	B
36194	Heat Exchanger – (Core Spray Pump Motor Coolers) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-78	3.2.1-051	A

Table 3.2.2-2 Core Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36195	Heat Exchanger – (Core Spray Pump Motor Coolers) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	VIII.E.SP-100	3.4.1-018	B
36192	Heat Exchanger – (Core Spray Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-76	3.2.1-050	C
36193	Heat Exchanger – (Core Spray Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	D
36864	Piping elements	Structural Integrity (Attached)	Glass	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
36865	Piping elements	Structural Integrity (Attached)	Glass	Condensation (Internal)	None	None	V.F.EP-66	3.2.1-060	A
35612	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
39037	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 2
35614	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35613	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35615	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
35616	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
35617	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35609	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36949	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36950	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35611	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35610	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35603	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B

Table 3.2.2-2 Core Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35604	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
35605	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
36123	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36128	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-27	3.2.1-046	A
38213	Pump Casing (Core Spray Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36133	Pump Casing (Core Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36132	Pump Casing (Core Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36130	Pump Casing (Core Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36129	Pump Casing (Core Spray Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36135	Pump Casing (Core Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36134	Pump Casing (Core Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36138	Pump Casing (Core Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3.1-072	B
36137	Pump Casing (Core Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36136	Pump Casing (Core Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36139	Pump Casing (Core Spray Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3.1-072	B
36078	Pump Casing (Core Spray Topping Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36079	Pump Casing (Core Spray Topping Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B

Table 3.2.2-2 Core Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36080	Pump Casing (Core Spray Topping Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
36201	Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			H, 1
36187	Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
36188	Tanks (Core Spray Pump Stuffing Box Lube Tank)	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36189	Tanks (Core Spray Pump Stuffing Box Lube Tank)	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-27	3.2.1-046	A
36190	Tanks (Core Spray Pump Suction Tanks)	Pressure Boundary	Carbon Steel	Concrete (External)	None	None	V.F.EP-112	3.2.1-055	A
38214	Tanks (Core Spray Pump Suction Tanks)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
36191	Tanks (Core Spray Pump Suction Tanks)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35619	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
35621	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
35620	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35623	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
35624	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
35625	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
35626	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
35628	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B

Table 3.2.2-2 Core Spray System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35627	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
35629	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
35630	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
35631	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
36081	Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
36082	Valve Body	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-27	3.2.1-046	A

Table 3.2.2-2 Core Spray System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage flow blockage/fouling of the stainless steel ECCS suction strainers.
2. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.7.

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37478	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2.1-014	B
37477	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2.1-015	B
37674	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37675	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
38091	Expansion Joints	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
38092	Expansion Joints	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-61b	3.2.1-048	B
37684	Heat Exchanger – (Emergency Condensers) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
37686	Heat Exchanger – (Emergency Condensers) Shell Side Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-27	3.2.1-046	C
38107	Heat Exchanger – (Emergency Condensers) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
37685	Heat Exchanger – (Emergency Condensers) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	D
37688	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-39	3.1.1-031	A
47688	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-031	B
37689	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-39	3.1.1-031	A
47689	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-031	B

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39226	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking, SCC/IGSCC	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-15	3.1.1-017	A, 5
49226	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking, SCC/IGSCC	Water Chemistry (B.2.1.2)	IV.C1.R-15	3.1.1-017	B, 5
37691	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking/Cyclic Loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-225	3.1.1-021	A, 5
47691	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking/Cyclic Loading	Water Chemistry (B.2.1.2)	IV.C1.R-225	3.1.1-021	E, 5, 6
39039	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 3
37690	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-39	3.1.1-031	A
47690	Heat Exchanger – (Emergency Condensers) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-031	B
37701	Heat Exchanger – (Emergency Condensers) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	D
37702	Heat Exchanger – (Emergency Condensers) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	D
37698	Heat Exchanger – (Emergency Condensers) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37700	Heat Exchanger – (Emergency Condensers) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	D
39040	Heat Exchanger – (Emergency Condensers) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 3
37699	Heat Exchanger – (Emergency Condensers) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37787	Heat Exchanger – (Emergency Condensers) Tubes	Heat Transfer	Stainless Steel	Treated Water (External)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	V.D2.EP-74	3.2.1-019	B
37786	Heat Exchanger – (Emergency Condensers) Tubes	Heat Transfer	Stainless Steel	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	V.D2.EP-74	3.2.1-019	B

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38080	Heat Exchanger – (Emergency Condensers) Tubes	Heat Transfer	Stainless Steel	Treated Water > 140°F (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	V.D2.EP-74	3.2.1-019	B
37697	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-39	3.1.1-031	A
47697	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-031	B
37694	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-39	3.1.1-031	A
47694	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-031	B
39225	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking, SCC/IGSCC	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-15	3.1.1-017	A, 5
49225	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking, SCC/IGSCC	Water Chemistry (B.2.1.2)	IV.C1.R-15	3.1.1-017	B, 5
37696	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking/Cyclic Loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-225	3.1.1-021	A, 5
47696	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking/Cyclic Loading	Water Chemistry (B.2.1.2)	IV.C1.R-225	3.1.1-021	E, 5, 6
39041	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 3
37695	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-39	3.1.1-031	A
47695	Heat Exchanger – (Emergency Condensers) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	IV.C1.RP-39	3.1.1-031	B
38081	Piping elements	Pressure Boundary	Glass	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
38082	Piping elements	Pressure Boundary	Glass	Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-060	A

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37774	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	V.E.EP-114b	3.2.1-042	I, 1
38478	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	V.E.E-444b	3.2.1-101	I, 1
37772	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-71	3.2.1-017	B
37681	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
39056	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 3
37683	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
37682	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
37802	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2.1-011	B
37703	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37704	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
37746	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37776	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	V.E.EP-114b	3.2.1-042	I, 1
38479	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	V.E.E-444b	3.2.1-101	I, 1
37777	Piping, piping components	Pressure Boundary	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-71	3.2.1-017	B
37743	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
38083	Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-27	3.2.1-046	A

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39054	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 3
37745	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
37744	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
38109	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2.1-011	B
37705	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37706	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
38087	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
39055	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 3
37747	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37749	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
37748	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37809	Tanks (Emergency Condenser Make Up Water Tanks)	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	V.E.E-444b	3.2.1-101	I, 4
37810	Tanks (Emergency Condenser Make Up Water Tanks)	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	V.E.EP-114b	3.2.1-042	I, 4
37783	Tanks (Emergency Condenser Make Up Water Tanks)	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	None	None	V.D2.E-443b	3.2.1-100	I, 4
37784	Tanks (Emergency Condenser Make Up Water Tanks)	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	none	None	V.D2.EP-3b	3.2.1-056	I, 4
37785	Tanks (Emergency Condenser Make Up Water Tanks)	Pressure Boundary	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-71	3.2.1-017	B
38088	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
38090	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38089	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
37780	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	V.E.EP-114b	3.2.1-042	I, 2
38480	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	V.E.E-444b	3.2.1-101	I, 2
37778	Valve Body	Pressure Boundary	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-71	3.2.1-017	B
37763	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-040	A
37765	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2.1-090	B
37764	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2.1-016	B
37707	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2.1-007	B
37708	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2.1-004	B
37750	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B
37752	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	V.D2.E-457	3.2.1-114	B
39042	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 3
37751	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. Components are constructed of a 3xxx series aluminum alloy which is not susceptible to stress corrosion cracking (NUREG-2192 Section 3.2.2.2.8). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, these components are not susceptible to loss of material due to pitting and crevice corrosion (NUREG-2192 Section 3.2.2.2.10).
2. Components are constructed of 6061-T6 aluminum alloy which is not susceptible to stress corrosion cracking (NUREG-2192 Section 3.2.2.2.8). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, loss of material due to pitting and crevice corrosion need not be managed (NUREG-2192 Section 3.2.2.2.10).
3. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.2.2-3 Emergency Cooling System Summary of Aging Management Evaluation

4. Components are constructed of 5052-H34 aluminum alloy, which contains less than 3.5 weight percent of magnesium, and is not susceptible to stress corrosion cracking (NUREG-2192 Section 3.2.2.2.8). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, loss of material due to pitting and crevice corrosion need not be managed (NUREG-2192 Section 3.2.2.2.10).
5. Augmented testing of the emergency condenser tubes and tube sheet includes radioactivity and temperature monitoring of the emergency condenser shell side water and visual inspection of the isolation condenser tubes.
6. The radioactivity and temperature monitoring of the emergency condenser shell side water is implemented through the Water Chemistry (B.2.1.2) program.

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.

- Circulating Water System (2.3.3.1)
- City Water System (2.3.3.2)
- Compressed Air Systems (2.3.3.3)
- Containment Systems (2.3.3.4)
- Control Room HVAC System (2.3.3.5)
- Cranes, Hoists, and Refueling Equipment System (2.3.3.6)
- Electric Steam Boiler System (2.3.3.7)
- Emergency Diesel Generator System (2.3.3.8)
- Fire Detection and Protection System (2.3.3.9)
- Liquid Poison System (2.3.3.10)
- Makeup Demineralizer System (2.3.3.11)
- Radioactive Waste System (2.3.3.12)
- Reactor Building Closed Loop Cooling System (2.3.3.13)
- Reactor Building HVAC System (2.3.3.14)
- Reactor Water Cleanup (2.3.3.15)
- Sampling System (2.3.3.16)
- Service Water System (2.3.3.17)
- Shutdown Cooling System (2.3.3.18)
- Spent Fuel Pool Cooling and Storage System (2.3.3.19)
- Turbine Building Closed Loop Cooling System (2.3.3.20)
- Turbine Building HVAC System (2.3.3.21)

3.3.2 RESULTS

The following tables summarize the results of the aging management review for Auxiliary Systems.

Table 3.3.2-1 Circulating Water System - Summary of Aging Management Evaluation

Table 3.3.2-2 City Water System - Summary of Aging Management Evaluation

Table 3.3.2-3 Compressed Air Systems - Summary of Aging Management Evaluation

Table 3.3.2-4 Containment Systems - Summary of Aging Management Evaluation

Table 3.3.2-5 Control Room HVAC System - Summary of Aging Management Evaluation

Table 3.3.2-6 Cranes, Hoists, and Refueling Equipment System - Summary of Aging Management Evaluation

Table 3.3.2-7 Electric Steam Boiler System - Summary of Aging Management Evaluation

Table 3.3.2-8 Emergency Diesel Generator System - Summary of Aging Management Evaluation

Table 3.3.2-9 Fire Detection and Protection System - Summary of Aging Management Evaluation

Table 3.3.2-10 Liquid Poison System - Summary of Aging Management Evaluation

Table 3.3.2-11 Makeup Demineralizer System - Summary of Aging Management Evaluation

Table 3.3.2-12 Radioactive Waste System - Summary of Aging Management Evaluation

Table 3.3.2-13 Reactor Building Closed Loop Cooling System - Summary of Aging Management Evaluation

Table 3.3.2-14 Reactor Building HVAC System - Summary of Aging Management Evaluation

Table 3.3.2-15 Reactor Water Cleanup - Summary of Aging Management Evaluation

Table 3.3.2-16 Sampling System - Summary of Aging Management Evaluation

Table 3.3.2-17 Service Water System - Summary of Aging Management Evaluation

Table 3.3.2-18 Shutdown Cooling System - Summary of Aging Management Evaluation

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System - Summary of Aging Management Evaluation

Table 3.3.2-20 Turbine Building Closed Loop Cooling System - Summary of Aging Management Evaluation

Table 3.3.2-21 Turbine Building HVAC System - Summary of Aging Management Evaluation

3.3.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.3.2.1.1 Circulating Water System

Materials

The materials of construction for the Circulating Water System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Concrete
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Elastomers
- Glass
- Polymer
- PVC
- Stainless Steel
- Stainless Steel Bolting

Environments

The Circulating Water System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Lubricating Oil
- Raw Water

Aging Effect Requiring Management

The following aging effects associated with the Circulating Water System components require management:

- Cracking
- Cracking or Blistering
- Flow Blockage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Hardening or Loss of Strength Due to Polymeric Degradation

- Long-Term Loss of Material
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear
- Loss of Material Due to Wear
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Circulating Water System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)

3.3.2.1.2 City Water System

Materials

The materials of construction for the City Water System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Galvanized Steel
- Glass
- Stainless Steel

Environments

The City Water System components are exposed to the following environments:

- Air - Indoor, Uncontrolled

- Condensation
- Raw Water
- Raw Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the City Water System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the City Water System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)

3.3.2.1.3 Compressed Air Systems

Materials

The materials of construction for the Compressed Air Systems components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc

- Elastomers
- Glass
- Polymer
- Stainless Steel
- Zinc

Environments

The Compressed Air Systems components are exposed to the following environments:

- Air - Dry
- Air - Indoor, Uncontrolled
- Air - Outdoor
- Closed Cycle Cooling Water
- Condensation
- Raw Water
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Compressed Air Systems components require management:

- Cracking
- Cracking or Blistering
- Flow Blockage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Hardening or Loss of Strength Due to Polymeric Degradation
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Compressed Air Systems components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)

3.3.2.1.4 Containment Systems

Materials

The materials of construction for the Containment Systems components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Stainless Steel
- Stainless Steel Bolting

Environments

The Containment Systems components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Closed Cycle Cooling Water
- Condensation
- Gas
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Containment Systems components require management:

- Cracking

- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Systems components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Water Chemistry (B.2.1.2)

3.3.2.1.5 Control Room HVAC System

Materials

The materials of construction for the Control Room HVAC System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Elastomers
- Galvanized Bolting
- Galvanized Steel
- Stainless Steel
- Stainless Steel Bolting

Environments

The Control Room HVAC System components are exposed to the following environments:

- Air - Indoor, Controlled

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Closed Cycle Cooling Water
- Condensation
- Gas

Aging Effect Requiring Management

The following aging effects associated with the Control Room HVAC System components require management:

- Cracking
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Long-Term Loss of Material
- Loss of Material
- Loss of Material Due to Wear
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Control Room HVAC System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)

3.3.2.1.6 Cranes, Hoists, and Refueling Equipment System

Materials

The materials of construction for the Cranes, Hoists, and Refueling Equipment System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel

- Stainless Steel Bolting

Environments

The Cranes, Hoists, and Refueling Equipment System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Cranes, Hoists, and Refueling Equipment System components require management:

- Cracking
- Cumulative Fatigue Damage
- Deformation
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Cranes, Hoists, and Refueling Equipment System components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.7 Electric Steam Boiler System

Materials

The materials of construction for the Electric Steam Boiler System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with less than 15% Zinc
- Elastomers
- Glass
- Stainless Steel

Environments

The Electric Steam Boiler System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Raw Water > 140°F
- Treated Water
- Treated Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Electric Steam Boiler System components require management:

- Cracking
- Cumulative Fatigue Damage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- 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 Electric Steam Boiler System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.8 Emergency Diesel Generator System

Materials

The materials of construction for the Emergency Diesel Generator System components are:

- Aluminum Alloy

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Galvanized Steel
- Glass
- Nickel Alloy
- Stainless Steel

Environments

The Emergency Diesel Generator System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Closed Cycle Cooling Water
- Closed Cycle Cooling Water > 140°F
- Condensation
- Diesel Exhaust
- Fuel Oil
- Lubricating Oil
- Lubricating Oil (Waste Oil)
- Raw Water
- Raw Water > 140°F
- Soil
- Underground

Aging Effect Requiring Management

The following aging effects associated with the Emergency Diesel Generator System components require management:

- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Long-Term Loss of Material

- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Emergency Diesel Generator System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.27)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Fuel Oil Chemistry (B.2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)
- TLAA

3.3.2.1.9 Fire Detection and Protection System

Materials

The materials of construction for the Fire Detection and Protection System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Cast Iron (with Internal Coatings)
- Cementitious Fireproofing
- Concrete
- Concrete Block
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc

- Elastomers
- Fiberglass
- Galvanized Steel
- Glass
- Nickel Alloy
- Polymer
- Reinforced Concrete
- Silicate Fireproofing
- Stainless Steel
- Stainless Steel Bolting

Environments

The Fire Detection and Protection System components are exposed to the following environments:

- Air - Dry
- Air - Indoor, Uncontrolled
- Air - Outdoor
- Condensation
- Diesel Exhaust
- Fuel Oil
- Gas
- Lubricating Oil
- Raw Water
- Soil
- Underground

Aging Effect Requiring Management

The following aging effects associated with the Fire Detection and Protection System components require management:

- Change in Material Properties
- Cracking
- Cracking or Blistering
- Cracking, Blistering, Loss of Material
- Cumulative Fatigue Damage

- Flow Blockage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Hardening or Loss of Strength Due to Polymeric Degradation
- Hardening, Loss of Strength, Shrinkage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear
- Loss of Material Due to Wear
- Loss of Preload
- Reduction of Heat Transfer
- Separation

Aging Management Programs

The following aging management programs manage the aging effects for the Fire Detection and Protection System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.27)
- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Fire Protection (B.2.1.15)
- Fire Water System (B.2.1.16)
- Fuel Oil Chemistry (B.2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- Lubricating Oil Analysis (B.2.1.25)
- Masonry Walls (B.2.1.32)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)
- Structures Monitoring (B.2.1.33)
- TLAA

3.3.2.1.10 Liquid Poison System

Materials

The materials of construction for the Liquid Poison System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Carbon Steel
- Stainless Steel
- Stainless Steel Bolting

Environments

The Liquid Poison System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Condensation
- Lubricating Oil
- Sodium Pentaborate Solution
- Treated Water
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Liquid Poison System components require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Liquid Poison System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)

- One-Time Inspection (B.2.1.20)
- Water Chemistry (B.2.1.2)

3.3.2.1.11 Makeup Demineralizer System

Materials

The materials of construction for the Makeup Demineralizer System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Cast Iron
- Cast Iron (with Internal Coatings)
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Glass
- Polymer
- PVC
- Stainless Steel
- Stainless Steel Bolting

Environments

The Makeup Demineralizer System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Condensation
- Raw Water
- Treated Water
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Makeup Demineralizer System components require management:

- Cracking

- Cracking or Blistering
- Hardening or Loss of Strength Due to Polymeric Degradation
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear
- Loss of Material Due to Wear
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Makeup Demineralizer System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.3.2.1.12 Radioactive Waste System

Materials

The materials of construction for the Radioactive Waste System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Elastomers
- Galvanized Steel
- Glass
- Stainless Steel

Environments

The Radioactive Waste System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Treated Water
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Radioactive Waste System components require management:

- Cracking
- Cumulative Fatigue Damage
- Flow Blockage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Long-Term Loss of Material
- Loss of Material
- Loss of Material Due to Wear
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Radioactive Waste System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.13 Reactor Building Closed Loop Cooling System

Materials

The materials of construction for the Reactor Building Closed Loop Cooling System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Galvanized Steel
- Glass
- Stainless Steel

Environments

The Reactor Building Closed Loop Cooling System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Gas
- Raw Water

Aging Effect Requiring Management

The following aging effects associated with the Reactor Building Closed Loop Cooling System components require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Building Closed Loop Cooling System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)

3.3.2.1.14 Reactor Building HVAC System

Materials

The materials of construction for the Reactor Building HVAC System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with less than 15% Zinc
- Elastomers
- Galvanized Bolting
- Galvanized Steel

Environments

The Reactor Building HVAC System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Condensation
- Raw Water

Aging Effect Requiring Management

The following aging effects associated with the Reactor Building HVAC System components require management:

- Flow Blockage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Long-Term Loss of Material
- Loss of Material
- Loss of Material Due to Wear

- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Building HVAC System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)

3.3.2.1.15 Reactor Water Cleanup

Materials

The materials of construction for the Reactor Water Cleanup components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Cast Austenitic Stainless Steel (CASS)
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Glass
- Polymer
- Stainless Steel
- Stainless Steel Bolting

Environments

The Reactor Water Cleanup components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Gas

- Lubricating Oil
- Treated Water
- Treated Water > 140°F
- Treated Water > 200°F
- Treated Water > 482°F

Aging Effect Requiring Management

The following aging effects associated with the Reactor Water Cleanup components require management:

- Cracking
- Cracking or Blistering
- Cumulative Fatigue Damage
- Hardening or Loss of Strength Due to Polymeric Degradation
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Fracture Toughness
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Water Cleanup components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)

- Selective Leaching (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.16 Sampling System

Materials

The materials of construction for the Sampling System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with less than 15% Zinc
- Elastomers
- Glass
- Nickel Alloy
- Polymer
- Stainless Steel

Environments

The Sampling System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Raw Water
- Treated Water
- Treated Water > 140°F
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Sampling System components require management:

- Cracking
- Cracking or Blistering
- Cumulative Fatigue Damage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Hardening or Loss of Strength Due to Polymeric Degradation

- Long-Term Loss of Material
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear
- Loss of Material Due to Wear
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Sampling System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.17 Service Water System

Materials

The materials of construction for the Service Water System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Elastomers
- Galvanized Steel
- Polymer
- PVC
- Stainless Steel
- Stainless Steel Bolting
- Titanium Alloy Bolting

Environments

The Service Water System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Condensation
- Lubricating Oil
- Raw Water

Aging Effect Requiring Management

The following aging effects associated with the Service Water System components require management:

- Cracking
- Cracking or Blistering
- Flow Blockage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Hardening or Loss of Strength Due to Polymeric Degradation
- Long-Term Loss of Material
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear
- Loss of Material Due to Wear
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Service Water System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)

3.3.2.1.18 Shutdown Cooling System

Materials

The materials of construction for the Shutdown Cooling System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Carbon Steel
- Copper Alloy with less than 15% Zinc
- Stainless Steel

Environments

The Shutdown Cooling System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Treated Water
- Treated Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Shutdown Cooling System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Shutdown Cooling System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- One-Time Inspection (B.2.1.20)

- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.19 Spent Fuel Pool Cooling and Storage System

Materials

The materials of construction for the Spent Fuel Pool Cooling and Storage System components are:

- Aluminum Alloy
- Boraflex
- Boral
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Elemental Carbon
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The Spent Fuel Pool Cooling and Storage System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Spent Fuel Pool Cooling and Storage System components require management:

- Cracking
- Cumulative Fatigue Damage

- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Reduction of Neutron Absorbing Capacity; Change in Dimensions and Loss of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Spent Fuel Pool Cooling and Storage System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.1.26)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.3.2.1.20 Turbine Building Closed Loop Cooling System

Materials

The materials of construction for the Turbine Building Closed Loop Cooling System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Copper Alloy with less than 15% Zinc Cladding
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Elastomers

- Glass
- Stainless Steel

Environments

The Turbine Building Closed Loop Cooling System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Raw Water

Aging Effect Requiring Management

The following aging effects associated with the Turbine Building Closed Loop Cooling System components require management:

- Cracking
- Flow Blockage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Material Due to Wear
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine Building Closed Loop Cooling System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- One-Time Inspection (B.2.1.20)

- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)

3.3.2.1.21 Turbine Building HVAC System

Materials

The materials of construction for the Turbine Building HVAC System components are:

- Aluminum Alloy
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Copper Alloy with less than 15% Zinc
- Elastomers
- Galvanized Bolting
- Galvanized Steel
- Stainless Steel Bolting

Environments

The Turbine Building HVAC System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Condensation
- Raw Water

Aging Effect Requiring Management

The following aging effects associated with the Turbine Building HVAC System components require management:

- Cracking
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Material Due to Wear

- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine Building HVAC System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)

3.3.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 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 programs are addressed in the following subsections.

3.3.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be TLAA's, as defined in 10 CFR 54.3 (TN4878). The TLAA's 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 TLAA's.

Table 3.3.1 Item Number 3.3.1-001: This item evaluates steel cranes: rails, bridges, structural members, structural components exposed to the environments of air-indoor uncontrolled for cumulative fatigue damage due to fatigue. Cumulative fatigue damage is managed as a TLAA for the Cranes, Hoists, and Refueling Equipment System as discussed in Section 4.7.

Table 3.3.1 Item Number 3.3.1-002: This item evaluates expansion joints, flow devices, fuel storage racks, heat exchanger components, piping, piping components, and valve bodies exposed to diesel exhaust, steam, treated water, treated water > 140°F, and treated water > 200°F for cumulative fatigue damage due to fatigue. Cumulative fatigue damage is managed as a TLAA for the Condensate and Condensate Transfer, Electric Steam Boiler, Emergency Cooling, Emergency Diesel Generator, Feedwater/High Pressure Coolant Injection, Fire Detection and Protection, Main Steam, Radioactive Waste, Reactor Coolant Pressure Boundary, Reactor Recirculation, Reactor Water

Cleanup, Sampling, Shutdown Cooling, and Spent Fuel Pool Cooling and Storage systems is discussed in Section 4.3.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

Cracking due to SCC and cyclic loading could occur in SS PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60°C (140°F) 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 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.

Table 3.3.1 Item Numbers 3.3.1-003 and 3.3.1-003a are applicable to PWRs only and are not used for NMP1.

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: (i) uninsulated, (ii) insulated, (iii) in the vicinity of insulated components, or (iv) 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 which requires management if: (i) plant-specific OE does not reveal a history of SCC and (ii) 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 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 cracking due to SCC: (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; (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 mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP will be used to manage the integrity of the coating. 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.

Table 3.3.1 Item Number 3.3.1-004: This item evaluates cracking due to SCC in stainless steel piping, piping components, and tanks exposed to air and condensation environments. Plant-specific operating experience (OE) from 2016 to 2026 associated with stainless steel and cast austenitic stainless steel (CASS) components in the Auxiliary Systems and Reactor Vessel, Internals, and Reactor Coolant System (non-Class 1 portions of the Control Rod Drive System) has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled, air-outdoor, and condensation has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel and CASS in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking due to SCC is not occurring in stainless steel and CASS components exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-094a: This item evaluates cracking due to SCC in stainless steel ducting and ducting components exposed to air and condensation environments. There are no stainless steel ducting, ducting components exposed to an environment of air-outdoor in Auxiliary Systems at NMP1. Plant-specific OE from 2016

to 2026 associated with stainless steel ducting and ducting components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking due to SCC is not occurring in stainless steel ducting and components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-146: This item evaluates cracking due to SCC in stainless steel underground piping, piping components, and tanks. Plant-specific OE from 2016 to 2026 associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of underground has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel in this environment, or as a result of transportable halogens. This provides objective evidence that the external surfaces of components in this environment are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking due to SCC is not occurring in stainless steel components exposed to an underground environment. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-205: This item evaluates cracking due to SCC in insulated stainless steel piping, piping components and tanks exposed to air and condensation environments. There are no insulated stainless steel piping, piping components and tanks exposed to the environments of air-indoor uncontrolled or air-outdoor in Auxiliary Systems at NMP1. Plant-specific OE from 2016 to 2026 associated with insulated stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the external environment of condensation has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at NMP1 for insulated stainless steel in this environment indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in SCC has not occurred. This provides objective evidence that the external surfaces of components in this environment are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking due to SCC is not occurring in insulated stainless steel components exposed to a condensation environment. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-231: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Auxiliary Systems.

Barrier coatings which isolate a component from aggressive environments are not credited.

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: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) 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 parts 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 which requires management for SS and nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (ii) 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 in the presence 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 a 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 mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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 for internal or external coatings.

Table 3.3.1 Item Number 3.3.1-006: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel-alloy piping and piping components exposed to air and condensation environments. There are no nickel-alloy piping or piping components in the Auxiliary Systems. Plant-specific OE from 2016 to 2026 associated with stainless steel and CASS components in the Auxiliary Systems and Reactor Vessel, Internals, and Reactor Coolant System (non-Class 1 portions of the Control Rod Drive System) has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled, air-outdoor, and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material due to pitting and crevice corrosion has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel and CASS in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in stainless steel and CASS components exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-094: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel ducting, ducting components exposed to air and condensation environments. There are no stainless steel ducting, ducting components exposed to an environment of air-outdoor in Auxiliary Systems at NMP1. Plant-specific OE from 2016 to 2026 associated with stainless steel ducting and ducting components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material

due to pitting and crevice corrosion. Loss of material due to pitting and crevice corrosion has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in stainless steel ducting and components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-222: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy tanks exposed to air and condensation environments. There are no nickel alloy tanks in Auxiliary Systems at NMP1. There are no stainless steel tanks exposed to air-outdoor in Auxiliary Systems at NMP1. Plant-specific OE from 2016 to 2026 associated with stainless steel components in the Auxiliary Systems and Reactor Vessel, Internals, and Reactor Coolant System (non-Class 1 portions of the Control Rod Drive System) has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in stainless steel components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-228: Not applicable. There are no 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 Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-232: This item evaluates loss of material due to pitting and crevice corrosion in insulated stainless steel and nickel-alloy piping, piping components, and tanks exposed to air and condensation environments. There are no insulated nickel-alloy piping, piping components, and tanks in Auxiliary Systems at NMP1. There are no insulated stainless steel piping, piping components and tanks exposed to the environments of air-indoor uncontrolled or air-outdoor in Auxiliary Systems at NMP1. Plant-specific OE from 2016 to 2026 associated with insulated stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the external environment of condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at NMP1 for insulated stainless steel in this environment indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated

component, resulting in loss of material has not occurred. This provides objective evidence that the external surfaces of components in this environment are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in insulated stainless steel components exposed to a condensation environment. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-241: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy heat exchanger components exposed to an air or condensation environment. There are no stainless steel and nickel alloy heat exchanger components exposed to the environments of air-outdoor or condensation in Auxiliary Systems at NMP1. Plant-specific OE from 2016 to 2026 associated with stainless steel and nickel alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of air-indoor uncontrolled has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel and nickel alloy in this environment, or as a result of transportable halogens. This provides objective evidence that the external surfaces of components in this environment are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in stainless steel and nickel alloy components exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.3.1 Item Number 3.3.1-246: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy underground piping, piping components, and tanks. There are no nickel-alloy piping, piping components, and tanks exposed to the environment of underground in Auxiliary Systems at NMP1. Plant-specific OE from 2016 to 2026 associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of underground has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel in this environment, or as a result of transportable halogens. This provides objective evidence that the external surfaces of components in this environment are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in stainless steel components exposed to an underground environment. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Barrier coatings which isolate a component from aggressive environments are not credited.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Subsequent License Renewal are discussed in Section B.1.3.

3.3.2.2.6 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, section A.1.6 and Appendix B, section B.1.4.

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: (i) a 10 year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (ii) a five 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 Section 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: (i) 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, (ii) the basis for the adequacy of augmented or lack of augmented inspections, (iii) the trend of which parameters will be followed 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), (iv) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (v) 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° 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 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 environments other than raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Table 3.3.1 Item Number 3.3.1-127: This item evaluates metallic piping, piping components, tanks exposed to raw water, raw water (potable), treated water, and waste water. Plant-specific OE from 2016 to 2026 has identified recurring internal corrosion (RIC) in carbon steel and cast iron piping exposed to raw water in the Service Water System and Fire Detection and Protection System. Recurring internal corrosion has also been identified in carbon steel and copper alloy with less than 15 percent zinc piping exposed to raw water (potable) in the City Water System.

As described below NMP1 will implement the Open-Cycle Cooling Water System (B.2.1.11) program to manage RIC in the Service Water System and Fire Detection and Protection System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Open Cycle Cooling Water System (B.2.1.11) program is described in Appendix B.

- i. The program utilizes volumetric (e.g., UT) examination methods for the detection of aging effects. These conventional NDE methods quantitatively evaluate components to verify fitness for service and have been proven effective for the detection of aging effects prior to loss of intended function.
- ii. The Open Cycle Cooling Water System (B.2.1.11) program includes methodology for choosing piping inspection locations and the performance of volumetric inspections for various degradation mechanisms including RIC. The current commitment for NRC Generic Letter (GL) 89-13 does not include a specified number or location of volumetric examinations. Instead, the number and prioritization of inspection locations is based on the risk associated with specific pipe locations balanced by other factors to investigate and address potential piping integrity concerns. The risk is determined by the combination of piping corrosion susceptibility (based on water quality, pipe material, pipe size, flow velocity, operating frequency (i.e., stagnant or intermittent flow), piping configuration, internal blockages, and prior repairs) and the consequences of pipe leaks or other integrity issues (e.g., piping below minimum required thickness). The extent of the inspection scope and criteria used when selecting inspection locations may include: inspections required for extent of condition, inspections required based on the risk factor, re-inspection locations based on NSI calculations, new inspection locations based on Industry/fleet OE, and follow up inspections on weld repairs or branch connection/half coupling repairs. The selection of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure is an acceptable approach to address RIC as required by this Further Evaluation.

Additionally, the Open Cycle Cooling Water System (B.2.1.11) program will be enhanced to perform a minimum of 10 inspections for recurring internal corrosion in the raw water systems, including water based fire systems, every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for recurring internal corrosion. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of re-inspection interval.

- iii. The program includes trending of corrosion data and the decision point where increased inspections would be implemented.
 - The program includes guidance for the determination of the NSI. This is the calculated time frame at which an inspection will be performed on the component based on current measured corrosion rate trending.
 - For inspections that do not meet acceptance criteria, the following code and non-code examination scope expansion criteria is procedurally mandatory for plants within their subsequent period of extended operation. 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; then no fewer than five additional inspections will be performed for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections.
- iv. Components that are not easily accessed (i.e., buried) are included in the evaluation of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure. Opportunistic visual inspection of the internal surface of inaccessible piping is performed during maintenance activities that provide access to the internal surfaces of these lines.
- v. The water-based fire protection system header pressure is maintained in standby above the motor drive fire pump and diesel driven fire pump auto start setpoints by two fire header pressure maintenance pumps. An auto start of the motor driven fire pump at the header low pressure setpoint is alarmed in the control room indicating low fire header pressure. An auto start of the diesel driven fire pump at the header low-low pressure setpoint is alarmed in the control room indicating low fire header pressure with a possible fire water system piping break. An unexpected start of either fire pump requires the response of an operator and investigation to determine the cause. These actions are sufficient activities for the identification of leaks in fire water system buried components.

NMP1 Service Water System does not include buried components.

As described below NMP1 will implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program to manage RIC in the City Water System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program is described in Appendix B.

- i. The program utilizes volumetric (e.g., UT) examination methods for the detection of aging effects. These conventional NDE methods quantitatively evaluate components to verify fitness for service and have been proven effective for the detection of aging effects prior to loss of intended function.
- ii. A minimum of five inspections will be performed for recurring internal corrosion every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for recurring internal corrosion. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of re-inspection interval.
- iii. The program includes trending of corrosion data and the decision point where increased inspections would be implemented. Additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the corrective action evaluations; however, there are no fewer than two additional inspections for each inspection that did not meet acceptance criteria, or 10 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections.
- iv. The City Water System does not include SSCs that are not easily accessible for inspections (e.g., underground). Additionally, the system is in-scope for leakage boundary only therefore there are no buried SSCs.
- v. The City Water System does not include SSCs that are not easily accessible for leak detection (e.g., underground). Additionally, the system is in-scope for leakage boundary only therefore there are no buried SSCs.

3.3.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

The 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 are provided for demonstrating that the specific material is not susceptible to SCC the ambient environment is not aggressive in nature. Cracking due to SCC is an aging effect that requires management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

3.3.2.2.8.1 Susceptible Material

If the material is not susceptible to SCC then cracking is not an aging effect which requires management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, that 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 type, 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 wt% 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 wt%*

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, 6063-T6, 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, and product form. For tempers not addressed above, the basis used to determine that the alloy is not susceptible and technical information substantiating the basis is added to the SLRA.

3.3.2.2.8.2 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 that requires management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys include the presence of 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 layer or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, halide concentrations sufficient 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. 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.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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 for internal or external coatings for internal or external coatings.

Table 3.3.1 Item Number 3.3.1-186: Not applicable. There are no 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 Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-189: This item evaluates cracking due to SCC in aluminum alloy piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), and waste water. There are no aluminum alloy piping, piping components, or tanks exposed to raw water (potable) and waste water in Auxiliary Systems. Plant-specific OE from 2016 to 2026 associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged

exposure to the environments of air-indoor uncontrolled, air-outdoor, condensation, and raw water has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking due to SCC is not occurring in aluminum alloy components exposed to air-indoor uncontrolled, air-outdoor, condensation, and raw water (non-potable). Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

The following component types in the identified systems are exposed to air-indoor uncontrolled, air-outdoor, or condensation environments but are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required.

- Makeup Demineralizer System / Piping, piping components: Components are constructed of 3xxx series (3003) aluminum alloy.
- Makeup Demineralizer System / Makeup Demineralized Water Storage Tank: Tank is constructed of 5xxx series (5052-H34) aluminum alloy that contains 2.2 - 2.8% magnesium by weight.
- Turbine Building HVAC System / Ducting and Components: The diesel generator building ventilation system exhaust hoods for the roof mounted ventilation blower housings are constructed of 6061-T6x aluminum alloy.

Table 3.3.1 Item Number 3.3.1-192: Not applicable. There are no aluminum underground piping, piping components, or tanks in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-233: Not applicable. There are no insulated aluminum piping, piping components, or tanks exposed to air or condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-254: Not applicable. There are no aluminum heat exchanger components exposed to air or condensation in Auxiliary Systems.

Barrier coatings which isolate a component from aggressive environments are not credited.

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 highly alkaline 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 highly alkaline 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 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 penetrate 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: (i) attributes of the concrete are consistent with ACI 318 (ACI 1997-TN8116) or ACI 349 (ACI 1985-TN8165) (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557 (NRC 1996-TN8063); (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) 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.

Table 3.3.1 Item Number 3.3.1-112: Not applicable. There are no steel piping, piping components exposed to concrete in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-202: Not applicable. There are no stainless steel piping, piping components exposed to concrete in Auxiliary Systems

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 greatly depends on the 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 which requires management for aluminum alloys if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) 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. Alternatively, loss of material due to pitting and crevice corrosion need not be managed if the type of aluminum is not susceptible to cracking and plant-specific operating experience does not reveal any issues related to loss of material due to pitting or crevice corrosion. 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 in the presence 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. The 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 a 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 GALL-SLR Report AMP XI.M32.

The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. 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," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Table 3.3.1 Item Number 3.3.1-223: Not Applicable. There are no aluminum underground piping, piping components, tanks in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-227: Not applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-234: This item evaluates loss of material due to pitting, crevice corrosion in aluminum piping, piping components, tanks exposed to air, and condensation. Plant-specific OE from 2016 to 2026 associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled, air-outdoor, and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in aluminum alloy components exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

The following component types in the identified systems are exposed to air-indoor uncontrolled, air-outdoor, or condensation environments but are constructed of aluminum alloys that are not susceptible to loss of material. Therefore, loss of material is not a predicted aging effect and aging management of these components for loss of material is not required.

- Makeup Demineralizer System / Piping, piping components: Components are constructed of 3xxx series (3003) aluminum alloy.
- Makeup Demineralizer System / Makeup Demineralized Water Storage Tank: Tank is constructed of 5xxx series (5052-H34) aluminum alloy that contains 2.2 - 2.8% magnesium by weight.
- Turbine Building HVAC System / Ducting and Components: The diesel generator building ventilation system exhaust hoods for the roof mounted ventilation blower housings are constructed of 6061-T6x aluminum alloy.

Table 3.3.1 Item Number 3.3.1-240: Not Applicable. There are no aluminum heat exchanger components exposed to waste water in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-242: Not Applicable. There are no aluminum heat exchanger components exposed to air, condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-245: Not Applicable. There are no insulated aluminum piping, piping components, tanks exposed to air, condensation in Auxiliary Systems.

Table 3.3.1 Item Number 3.3.1-247: This item evaluates loss of material due to pitting, crevice corrosion in aluminum piping, piping components, tanks exposed to raw water and waste water. There are no aluminum piping, piping components, and tanks exposed to waste water in Auxiliary Systems. Plant-specific OE from 2016 to 2026 associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of raw water has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified

through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in this environment, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal surfaces of components in this environment are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in aluminum alloy components exposed to raw water. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Barrier coatings which isolate a component from aggressive environments are not credited.

3.3.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Auxiliary Systems components:

- Section 4.3.4, ASME Section III, Class 2 and 3, and ANSI B31.1 Allowable Stress Analyses and HELB Exclusions of Recirculation Piping Analysis
- Section 4.7.8, Cranes Cyclic Loading Analysis

3.3.3 CONCLUSION

The Auxiliary Systems piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Auxiliary Systems components are identified in the summaries in Section 3.3.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Auxiliary Systems components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR) Section 4.7 "Other Plant-Specific TLAAs"	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 3.3.2.2.1.
3.3.1-002	Stainless steel (SS), 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	Fatigue is a TLAA; further evaluation is documented in Subsection 3.3.2.2.1.
3.3.1-003	PWR Only				
3.3.1-003a	PWR Only				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-004	SS 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the cast austenitic stainless steel (CASS) and stainless steel accumulators, electric heaters, expansion joints, flexible connections, flow devices, heat exchanger components, hoses, piping, piping components, pump casings, rupture disks, silencers / mufflers, spray nozzles, strainer (elements), tanks, and valve bodies exposed to air - indoor, uncontrolled, air - outdoor, and condensation in the Circulating Water System, City Water System, Compressed Air Systems, Containment Systems, Electric Steam Boiler System, Emergency Diesel Generator System, Fire Detection and Protection System, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Water Cleanup, Sampling System, Service Water System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.3.
3.3.1-005	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-006	SS, 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the cast austenitic stainless steel (CASS) and stainless steel accumulators, electric heaters, expansion joints, flexible connections, flow devices, heat exchanger components, hoses, piping, piping components, pump casings, rupture disks, silencers / mufflers, spray nozzles, strainer (elements), tanks, and valve bodies exposed to air - indoor, uncontrolled, air - outdoor, and condensation in the Circulating Water System, City Water System, Compressed Air Systems, Containment Systems, Electric Steam Boiler System, Emergency Diesel Generator System, Fire Detection and Protection System, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Water Cleanup, Sampling System, Service Water System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.4.
3.3.1-007	PWR Only				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-008	PWR Only				
3.3.1-009	PWR Only				
3.3.1-010	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC, cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not Applicable. There are no high-strength steel closure bolting exposed to air, soil, underground in Auxiliary Systems.
3.3.1-011	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-012	Steel; SS, 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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel and stainless steel closure bolting exposed to air - indoor, uncontrolled, air - outdoor, and condensation in the Circulating Water System, City Water System, Compressed Air Systems, Containment Systems, Control Room HVAC System, Electric Steam Boiler System, Emergency Diesel Generator System, Fire Detection and Protection System, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Building HVAC System, Reactor Water Cleanup, Sampling System, Service Water System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, Control Rod Drive System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.3.1-013	This Item Number is not listed in NUREG-2192.				
3.3.1-014	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of the carbon and low alloy steel, stainless steel, and titanium closure bolting exposed to air - indoor, uncontrolled, air - outdoor, condensation, raw water, soil, treated water and underground environment in the Circulating Water System, City Water System, Compressed Air Systems, Containment Systems, Control Room HVAC System, Electric Steam Boiler System, Emergency Diesel Generator System, Fire Detection and Protection System, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Building HVAC System, Reactor Water Cleanup, Sampling System, Service Water System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, Control Rod Drive System, and Reactor Recirculation System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-016	SS piping, piping components outboard the second containment isolation valves with a diameter ≥ 4 in. nominal pipe size (NPS) exposed to treated water $>93^{\circ}\text{C}$ ($>200^{\circ}\text{F}$)	Cracking due to SCC, intergranular stress corrosion cracking (IGSCC)	AMP XI.M2, "Water Chemistry," and AMP XI.M25, "BWR Reactor Water Cleanup System"	No	Not Used. Cracking due to SCC, intergranular stress corrosion cracking (IGSCC) in stainless steel Reactor Water Cleanup piping, piping components outboard the second containment isolation valves with a diameter ≥ 4 in. nominal pipe size (NPS) exposed to treated water $>93^{\circ}\text{C}$ ($>200^{\circ}\text{F}$) is addressed in Item Number 3.3.1-110.
3.3.1-017	SS heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry"	No	Not Used. The reduction of heat transfer due to fouling in stainless steel Shutdown Cooling System heat exchanger tubes exposed to treated water is addressed in Item Number 3.3.1-027. There are no stainless steel heat exchanger tubes exposed to treated borated water in Auxiliary Systems.
3.3.1-018	SS high pressure pump casing, piping, piping components, tanks exposed to treated borated water $>60^{\circ}\text{C}$ ($>140^{\circ}\text{F}$), sodium pentaborate solution $>60^{\circ}\text{C}$ ($>140^{\circ}\text{F}$)	Cracking due to SCC	AMP XI.M2, "Water Chemistry"	No	Not Applicable. There are no stainless steel high pressure pump casing, piping, piping components, tanks exposed to treated borated water $>60^{\circ}\text{C}$ ($>140^{\circ}\text{F}$), sodium pentaborate solution $>60^{\circ}\text{C}$ ($>140^{\circ}\text{F}$) in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-019	SS regenerative heat exchanger components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel regenerative and non-regenerative heat exchanger components exposed to treated water > 140°F in the Reactor Water Cleanup. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.3.1-020	SS, steel with SS 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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon or low alloy steel with stainless steel cladding and stainless steel heat exchanger components exposed to reactor coolant and treated water > 140°F in the Electric Steam Boiler System, Reactor Water Cleanup, Sampling System, Shutdown Cooling System, and Reactor Recirculation System. There are no stainless steel, steel with stainless steel cladding heat exchanger components exposed to treated borated water >60°C (>140°F) in Auxiliary Systems. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-021	Steel piping, piping components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, microbiologically-induced corrosion (MIC)	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel and cast iron boiler casings, heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to treated water in the Containment Systems, Electric Steam Boiler System, Liquid Poison System, Radioactive Waste System, Reactor Water Cleanup, Sampling System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the copper alloy heat exchanger components, piping, piping components, pump casings, and valve bodies exposed to treated water in the Electric Steam Boiler System, Makeup Demineralizer System, Reactor Water Cleanup, Sampling System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, Core Spray System, and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-023	This Item Number is not listed in NUREG-2192.				
3.3.1-024	This Item Number is not listed in NUREG-2192.				
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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the aluminum and aluminum alloy crane/hoist (fuel prep machine), piping, piping components, spent fuel pool gates, tanks, and valve bodies exposed to treated water in the Cranes, Hoists, and Refueling Equipment System, Makeup Demineralizer System, Spent Fuel Pool Cooling and Storage System, and Reactor Building. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program has been added as an additional aging management program for condition monitoring of the aluminum alloy crane/hoist (fuel prep machine) exposed to treated water in the Cranes, Hoists, and Refueling Equipment System. There are no aluminum piping, piping components exposed to treated borated water in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-026	Steel (with SS 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"	No	Not Applicable. There are no steel (with stainless steel cladding) piping, piping components exposed to treated water in Auxiliary Systems.
3.3.1-027	SS heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage reduction of heat transfer of the stainless steel heat exchanger tubes exposed to treated water in the Shutdown Cooling System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.3.1-028	PWR Only				
3.3.1-029	This Item Number is not listed in NUREG-2192.				
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. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage cracking and loss of material of the concrete piping, piping components exposed to raw water in the Circulating Water System. Flow blockage due to fouling is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-030a	Fiberglass, high-density polyethylene (HDPE) piping, piping components exposed to raw water	Cracking, blistering, loss of material due to exposure to radiation, temperature, or moisture; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System" or AMP XI.M43, "High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping"	No	Not Applicable. There are no fiberglass, high-density polyethylene (HDPE) piping, piping components exposed to raw water in Auxiliary Systems.
3.3.1-031	This Item Number is not listed in NUREG-2192.				
3.3.1-032	This Item Number is not listed in NUREG-2192.				
3.3.1-032a	This Item Number is not listed in NUREG-2192.				
3.3.1-033	This Item Number is not listed in NUREG-2192.				
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. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the copper alloy piping, piping components, and valve bodies exposed to raw water in the Circulating Water System, Emergency Diesel Generator System, and Service Water System.
3.3.1-035	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-036	This Item Number is not listed in NUREG-2192.				
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. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the carbon steel, cast iron, and galvanized steel heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to raw water in the Circulating Water System, Emergency Diesel Generator System, Reactor Building HVAC System, Service Water System, and Condensate and Condensate Transfer System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the carbon steel and copper alloy heat exchanger components exposed to raw water in the Circulating Water System, Emergency Diesel Generator System, Reactor Building Closed Loop Cooling System, Reactor Building HVAC System, Service Water System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, and Containment Spray System. The Open-Cycle Cooling Water System (B.2.1.11) program will also be used to manage flow blockage of the carbon steel (with internal coatings) heat exchanger components in the Turbine Building Closed Loop Cooling System. Loss of material in these components is addressed in Item Number 3.3.1-139.
3.3.1-039	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-040	SS 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. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage flow blockage and loss of material of the stainless steel flexible connections, flow devices, heat exchanger components, hoses, piping, piping components, pump casings, strainer (elements), traveling water screens, and valve bodies exposed to raw water in the Circulating Water System, Containment Spray System, Electric Steam Boiler System, Emergency Diesel Generator System, Reactor Building Closed Loop Cooling System, and Service Water System.
3.3.1-041	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-042	Copper alloy, titanium, SS 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. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage reduction of heat transfer of the copper alloy and stainless steel heat exchanger components exposed to raw water in the Emergency Diesel Generator System, Reactor Building Closed Loop Cooling System, Service Water System, and Turbine Building Closed Loop Cooling System. Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage reduction of heat transfer of the copper alloy heat exchanger components exposed to raw water in the Fire Detection and Protection System.
3.3.1-043	SS piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage cracking of the stainless steel valve bodies exposed to closed cycle cooling water > 140°F in the Emergency Diesel Generator System.
3.3.1-044	SS; 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	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage cracking of the stainless steel heat exchanger components exposed to closed cycle cooling water > 140°F in the Emergency Diesel Generator System and Reactor Recirculation System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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 System"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the carbon steel, cast iron, and galvanized steel piping, piping components, pump casings, tanks, and valve bodies exposed to closed cycle cooling water in the Control Room HVAC System, Emergency Diesel Generator System, Reactor Building Closed Loop Cooling System, and Turbine Building Closed Loop Cooling System.
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. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the carbon steel, cast iron, and copper alloy heat exchanger components, hoses, piping, piping components, and valve bodies exposed to closed cycle cooling water in the Compressed Air Systems, Containment Systems, Control Room HVAC System, Emergency Diesel Generator System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Water Cleanup, Sampling System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, and Turbine Building Closed Loop Cooling System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-047	SS; steel with SS 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	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the stainless steel heat exchanger components exposed to closed cycle cooling water in the Emergency Diesel Generator System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Water Cleanup, Sampling System, and Shutdown Cooling System.
3.3.1-048	Aluminum piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no aluminum piping, piping components exposed to closed-cycle cooling water in Auxiliary Systems.
3.3.1-049	SS 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. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the stainless steel flow devices, piping, piping components, pump casings, and valve bodies exposed to closed cycle cooling water in the Control Room HVAC System, Emergency Diesel Generator System, Reactor Building Closed Loop Cooling System, Sampling System, and Turbine Building Closed Loop Cooling System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-050	SS, 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. The Closed Treated Water Systems (B.2.1.12) program will be used to manage reduction of heat transfer of the copper alloy and stainless steel heat exchanger components exposed to closed cycle cooling water in the Compressed Air Systems, Control Room HVAC System, Emergency Diesel Generator System, Reactor Building Closed Loop Cooling System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, and Turbine Building Closed Loop Cooling System.
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. NMP1 Technical Specification Amendment 234 removed credit for the Boraflex neutron absorber material in the two remaining spent fuel racks that contain Boraflex, based on a 3 out of 4 fuel loading pattern with cell blockers reducing the Boraflex rack capacity from 414 to 306 fuel storage locations. Therefore, the reduction of neutron-absorbing capacity is not an applicable aging effect.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program will be used to manage cracking, deformation, and loss of material of the carbon steel crane/hoist (refueling platform) and crane/hoist: rails, bridges, structural members, and structural components exposed to air - indoor, uncontrolled in the Cranes, Hoists, and Refueling Equipment System.
3.3.1-053	This Item Number is not listed in NUREG-2192.				
3.3.1-054	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel, cast iron, and galvanized steel compressor housings, heat exchanger components, piping, piping components, silencers, strainer (elements), tanks, and valve bodies exposed to condensation in the Compressed Air Systems, Containment Systems, Control Room HVAC System, Emergency Diesel Generator System, Fire Detection and Protection System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building HVAC System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, and Control Rod Drive System.
3.3.1-056	This Item Number is not listed in NUREG-2192.				
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. The Fire Protection (B.2.1.15) program will be used to manage hardening, loss of strength, and shrinkage of the elastomer fire barriers (penetration seals) exposed to air - indoor, uncontrolled in the Fire Detection and Protection System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Fire Protection (B.2.1.15) program will be used to manage loss of material of the carbon steel and galvanized steel fire barriers (doors), fire barriers (penetration seals), piping, piping components, spray nozzles, tanks, and valve bodies exposed to air - indoor, uncontrolled, air - outdoor, and condensation in the Fire Detection and Protection System.
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. The Fire Protection (B.2.1.15) program will be used to manage loss of material due to wear of the carbon steel fire barriers (doors) exposed to air - indoor, uncontrolled and air - outdoor in the Fire Detection and Protection System.
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, pop out, or scaling	AMP XI.M26, "Fire Protection," and AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exceptions. The Fire Protection (B.2.1.15) and Structures Monitoring (B.2.1.33) programs will be used to manage cracking and loss of material of the reinforced concrete fire barriers (concrete curbs, walls, ceilings, floors) exposed to air - indoor, uncontrolled and air - outdoor in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Structures Monitoring (B.2.1.33) program implementation.
3.3.1-061	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-062	This Item Number is not listed in NUREG-2192.				
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. The Fire Water System (B.2.1.16) program will be used to manage flow blockage and loss of material of the cast iron fire hydrants exposed to air - outdoor and raw water in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.16) 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. The Fire Water System (B.2.1.16) program will be used to manage flow blockage and loss of material of the carbon steel, cast iron, and copper alloy piping, piping components, pump casings, tanks, and valve bodies exposed to raw water in the Fire Detection and Protection System. The Fire Water System (B.2.1.16) program will also be used to manage flow blockage of the cast iron (with internal coatings) piping, piping components in the Fire Detection and Protection System. Loss of material in these components is addressed in Item Number 3.3.1-139. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.16) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-065	Aluminum piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no aluminum piping, piping components in the Fire Detection and Protection System exposed to raw water, treated water, or raw water (potable).
3.3.1-066	SS 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. The Fire Water System (B.2.1.16) program will be used to manage flow blockage and loss of material of the stainless steel flow devices, pump casings, and strainer (elements) exposed to raw water in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.16) program implementation.
3.3.1-067	This Item Number is not listed in NUREG-2192.				
3.3.1-068	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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"	No	Consistent with NUREG-2191 with exceptions. The Fuel Oil Chemistry (B.2.1.18) program will be used to manage loss of material of the copper alloy hoses and valve bodies exposed to fuel oil in the Emergency Diesel Generator System and Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B.2.1.18) 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"	No	Consistent with NUREG-2191 with exceptions. The Fuel Oil Chemistry (B.2.1.18) program will be used to manage loss of material of the carbon steel and cast iron piping, piping components, pump casings, and tanks exposed to fuel oil in the Emergency Diesel Generator System and Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B.2.1.18) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-071	Stainless steel, aluminum, nickel-alloy piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Fuel Oil Chemistry (B.2.1.18) program will be used to manage loss of material of the nickel alloy and stainless steel piping, piping components and strainer (elements) exposed to fuel oil in the Emergency Diesel Generator System and Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B.2.1.18) program implementation.

3.3.1-072	Gray cast iron, ductile iron, malleable iron, copper alloy (>15% zinc or >8% aluminum) 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 with exceptions. The Selective Leaching (B.2.1.21) program will be used to manage LOM due to selective leaching of the cast iron and copper alloy with 15% or > zinc fire hydrants, HX components, piping, pump casings, steel components, & tanks exposed to CCCW, raw water, soil, treated water, & waste water in Circulating Water System, City Water System, Compressed Air Systems, Control Room HVAC System, Emergency Diesel Generator System, Fire Detection and Protection System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Water Cleanup, Service Water System, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, Containment Spray System, Core Spray System, Control Rod Drive System, Main Generator and Auxiliary System, & Screen and Pump House Building. LOM due to selective leaching of HX tubes fabricated from admiralty brass (inhibited brass) and exposed to CCCW, raw water, TW, and waste water is not an applicable aging effect requiring management consistent with NUREG-2191 Table IX.C for inhibited brass. Heat exchanger tubes fabricated from inhibited brass are identified through plant-specific notes provided in SLRA Table 3.3.2-12 for the Radioactive Waste System, Table 3.3.2-19 for the Spent Fuel Pool Cooling and Storage System, and Table 3.3.2-21 for the Turbine Building Closed Loop Cooling System.
3.3.1-073	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement,	Cracking due to chemical reaction, weathering, or corrosion of	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
	cementitious piping, piping components exposed to air – outdoor	reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, pop out, or scaling			cement, cementitious piping, piping components exposed to air - outdoor in Auxiliary Systems.
3.3.1-074	This Item Number is not listed in NUREG-2192.				
3.3.1-075	This Item Number is not listed in NUREG-2192.				
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 External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage hardening or loss of strength due to elastomeric degradation of the elastomer expansion joints, flexible connections, hoses, piping, and piping components exposed to air - indoor, uncontrolled in the Circulating Water System, Compressed Air Systems, Control Room HVAC System, Electric Steam Boiler System, Fire Detection and Protection System, Radioactive Waste System, Reactor Building HVAC System, Sampling System, Service Water System, Turbine Building Closed Loop Cooling System, and Turbine Building HVAC System.
3.3.1-077	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon steel, cast iron, and galvanized steel accumulators, boiler casings, compressor housings, drip pans, ducting and components, gearboxes, heat exchanger components, hose stations, mufflers, piping, piping components, pump casings, silencer / mufflers, tanks, and valve bodies exposed to air - indoor, uncontrolled, air - outdoor, and condensation in the Circulating Water System, City Water System, Compressed Air Systems, Containment Systems, Control Room HVAC System, Electric Steam Boiler System, Emergency Diesel Generator System, Fire Detection and Protection System, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Building HVAC System, Reactor Water Cleanup, Sampling System, Service Water System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, and Control Rod Drive System.
3.3.1-079	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-080	Steel heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon steel and cast iron heat exchanger components exposed to air - indoor, uncontrolled in the Circulating Water System, Compressed Air Systems, Control Room HVAC System, Emergency Diesel Generator System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Water Cleanup, Sampling System, Shutdown Cooling System, and Turbine Building Closed Loop Cooling System.
3.3.1-081	This Item Number is not listed in NUREG-2192.				
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 External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material due to wear of the elastomer expansion joints, flexible connections, and hoses exposed to air - indoor, uncontrolled in the Circulating Water System, Control Room HVAC System, Fire Detection and Protection System, Radioactive Waste System, Reactor Building HVAC System, Sampling System, Service Water System, Turbine Building Closed Loop Cooling System, and Turbine Building HVAC System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-083	SS 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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage cracking of the stainless steel expansion joints exposed to diesel exhaust in the Emergency Diesel Generator System and Fire Detection and Protection System.
3.3.1-084	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage hardening or loss of strength due to elastomeric degradation of the elastomer expansion joints, flexible connections, hoses, piping, and piping components exposed to air - dry, closed cycle cooling water, condensation, fuel oil, gas, lubricating oil, raw water, treated water, and waste water in the Circulating Water System, Compressed Air Systems, Control Room HVAC System, Electric Steam Boiler System, Fire Detection and Protection System, Radioactive Waste System, Reactor Building HVAC System, Sampling System, Service Water System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, and Condensate and Condensate Transfer System. Flow blockage due to fouling in elastomer expansion joints and hoses exposed to raw water in the Circulating Water System, Sampling System, and Service Water System is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply.
3.3.1-086	This Item Number is not listed in NUREG-2192.				
3.3.1-087	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-088	Steel; SS 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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel, cast iron, galvanized steel, and stainless steel expansion joints, mufflers, piping, piping components, pump casings, silencers / mufflers, and valve bodies exposed to diesel exhaust and raw water in the City Water System, Emergency Diesel Generator System, and Fire Detection and Protection System. Flow blockage due to fouling in carbon steel, cast iron, and galvanized steel piping, piping components, pump casings, and valve bodies exposed to raw water in the City Water System is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply.
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. There are no steel piping, piping components exposed to condensation (internal) in the fire water portion of the Fire Detection and Protection System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel and galvanized steel ducting and components, heat exchanger components, and silencers / mufflers exposed to condensation in the Control Room HVAC System, Reactor Building HVAC System, and Turbine Building HVAC System.
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage flow blockage and loss of material of the carbon steel, cast iron, and galvanized steel drip pans, heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to waste water in the Compressed Air Systems, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Sampling System, Condensate and Condensate Transfer System, and Main Turbine and Auxiliary System.
3.3.1-092	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-093	Copper alloy piping, piping components exposed to raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the copper alloy piping, piping components, pump casings, and valve bodies exposed to raw water in the City Water System.
3.3.1-094	SS 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the stainless steel ducting and components exposed to air - indoor, uncontrolled and condensation in the Control Room HVAC System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.4.
3.3.1-094a	SS 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the stainless steel ducting and components exposed to air - indoor, uncontrolled and condensation in the Control Room HVAC System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.3.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage flow blockage and loss of material of the copper alloy and stainless steel heat exchanger components, piping, piping components, tanks, and valve bodies exposed to waste water in the Compressed Air Systems, Makeup Demineralizer System, Radioactive Waste System, Condensate and Condensate Transfer System, and Main Generator and Auxiliary System.
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material due to wear of the elastomer expansion joints and hoses exposed to raw water, treated water, and waste water in the Circulating Water System, Radioactive Waste System, Sampling System, Service Water System, and Condensate and Condensate Transfer System. Flow blockage due to fouling in elastomer expansion joints and hoses exposed to raw water and waste water in the Circulating Water System, Sampling System, Service Water System, and Radioactive Waste System is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-096a	Steel, aluminum, copper alloy, SS, 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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage reduction of heat transfer of the aluminum alloy and copper alloy heat exchanger components exposed to condensation in the Control Room HVAC System and Emergency Diesel Generator System.
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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon steel heat exchanger components exposed to condensation in the Control Room HVAC System, Reactor Building HVAC System, and Turbine Building HVAC System.
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"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the carbon steel and cast iron gearboxes, piping, piping components, pump casings, strainer (elements), tanks, and valve bodies exposed to lubricating oil in the Circulating Water System, Emergency Diesel Generator System, Liquid Poison System, Reactor Water Cleanup, and Control Rod Drive System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the carbon steel and cast iron heat exchanger components exposed to lubricating oil in the Emergency Diesel Generator System, Reactor Water Cleanup, and Control Rod Drive System.
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"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the aluminum alloy and copper alloy heat exchanger components, hoses, piping, piping components, and valve bodies exposed to lubricating oil in the Emergency Diesel Generator System, Fire Detection and Protection System, Reactor Water Cleanup, Service Water System, and Control Rod Drive System.
3.3.1-100	SS piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the stainless steel flow devices, heat exchanger components, hoses, piping, piping components, and valve bodies exposed to lubricating oil in the Emergency Diesel Generator System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage reduction of heat transfer of the aluminum alloy heat exchanger components exposed to lubricating oil in the Emergency Diesel Generator System.
3.3.1-102	Boral®; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	AMP XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Consistent with NUREG-2191. The Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.1.26) program will be used to manage reduction of neutron absorbing capacity, change in dimensions, and loss of material of the boral fuel storage racks exposed to treated water in the Spent Fuel Pool Cooling and Storage System.
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 exceptions. The Buried and Underground Piping and Tanks (B.2.1.27) program will be used to manage cracking and loss of material of the concrete piping, piping components exposed to soil in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks (B.2.1.27) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-104	HDPE, carbon fiber reinforced polymer (CFRP), fiberglass piping, piping components exposed to soil, concrete	Cracking, blistering, loss of material due to wear, general corrosion (metal substrate), erosion, chemical attack, exposure to temperature or moisture	AMP XI.M41, "Buried and Underground Piping and Tanks" or AMP XI.M43, "High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping"	No	Consistent with NUREG-2191 with exceptions. The Buried and Underground Piping and Tanks (B.2.1.27) program will be used to manage cracking, blistering, and loss of material of the fiberglass tanks exposed to soil in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks (B.2.1.27) program implementation.
3.3.1-105	This Item Number is not listed in NUREG-2192.				
3.3.1-106	This Item Number is not listed in NUREG-2192.				
3.3.1-107	SS, nickel-alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no stainless steel, nickel-alloy piping, piping components exposed to soil, concrete in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-108	Titanium, super austenitic, copper alloy, stainless steel, nickel-alloy piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC (super austenitic, copper alloy, stainless steel, nickel-alloy; soil environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Buried and Underground Piping and Tanks (B.2.1.27) program will be used to manage loss of material of the copper alloy valve bodies exposed to an underground environment in the Emergency Diesel Generator System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks (B.2.1.27) program implementation.
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 with exceptions. The Buried and Underground Piping and Tanks (B.2.1.27) program will be used to manage loss of material of the carbon and low alloy steel bolting, carbon steel, and cast iron bolting (closure), fire hydrant, piping, piping components, tanks, and valve bodies exposed to soil and an underground environment in the Emergency Diesel Generator System and Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks (B.2.1.27) program implementation.
3.3.1-109a	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-110	SS, nickel-alloy piping, piping components ≥ 4 NPS exposed to treated water $> 93^{\circ}\text{C}$ ($> 200^{\circ}\text{F}$)	Cracking due to SCC, IGSCC	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the stainless steel piping, piping components: Class 1 greater than or equal to 4" NPS exposed to treated water $> 200^{\circ}\text{F}$ in the Reactor Water Cleanup System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material of the carbon steel fuel storage racks exposed to air - indoor, uncontrolled in the Reactor Building. Exceptions apply to the NUREG-2191 recommendations for Structures Monitoring (B.2.1.33) program implementation.
3.3.1-112	Steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no steel piping, piping components exposed to concrete in Auxiliary Systems. See Subsection 3.3.2.2.9.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-113	Aluminum piping, piping components exposed to gas	None	None	No	Not Applicable. There are no aluminum piping, piping components exposed to gas in Auxiliary Systems.
3.3.1-114	Copper alloy heat exchanger components, tanks, 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. There are no copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in Auxiliary Systems.
3.3.1-116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Consistent with NUREG-2191.
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.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-118	This Item Number is not listed in NUREG-2192.				
3.3.1-119	Nickel-alloy, polyvinyl chloride (PVC), glass piping, piping components exposed to air with borated water leakage, air – indoor uncontrolled, condensation, waste water, raw water (potable)	None	None	No	Consistent with NUREG-2191.
3.3.1-120	SS 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	Not Applicable. There are no titanium heat exchanger components, piping, piping components exposed to air - indoor, uncontrolled or air - outdoor in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not Applicable. There are no titanium heat exchanger components other than tubes, piping and piping components exposed to raw water in Auxiliary Systems.
3.3.1-124	SS, steel (with SS 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"	No	Not Applicable. There are no stainless steel, steel (with stainless steel or nickel-alloy cladding) spent fuel storage racks, piping, piping components exposed to treated water >60°C (>140°F) in Auxiliary Systems.
3.3.1-125	SS, steel (with SS 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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the stainless steel bolting and fuel storage racks exposed to treated water in the Spent Fuel Pool Cooling and Storage System and Reactor Building. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not applicable. There are no metallic piping, piping components exposed to treated water, treated borated water, raw water with the aging effect/mechanism of wall thinning due to erosion in Auxiliary Systems.
3.3.1-127	Metallic piping, piping components, tanks exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel and copper alloy piping, piping components exposed to raw water in the City Water System. Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage loss of material of the carbon steel and cast iron piping, piping components exposed to raw water in the Fire Detection and Protection System and Service Water System. See Subsection 3.3.2.2.7.
3.3.1-128	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water	Loss of material due to general, pitting, crevice corrosion, MIC (soil, raw water only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-129	This Item Number is not listed in NUREG-2192.				
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. The Fire Water System (B.2.1.16) program will be used to manage flow blockage and loss of material of the copper alloy spray nozzles and sprinklers exposed to condensation and raw water in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.16) program implementation.
3.3.1-131	Steel, SS, copper alloy, aluminum piping, piping components exposed to air, condensation	Flow blockage due to fouling	AMP XI.M27, "Fire Water System"	No	Not used. Flow blockage in copper alloy spray nozzles and sprinklers exposed to condensation in the Fire Detection and Protection System is addressed in item Number 3.3.1-130.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the insulated carbon steel, cast iron, copper alloy with 15% zinc or more, and galvanized steel ducting and components, heat exchanger components, piping, piping components, pump casings tanks, and valve bodies exposed to condensation in the Control Room HVAC System, Service Water System, and Turbine Building Closed Loop Cooling System. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking of the copper alloy with 15% zinc or more insulated valve bodies exposed to condensation in the Control Room HVAC System.
3.3.1-133	HDPE, CFRP underground piping, piping components	Cracking, blistering, loss of material due to wear, general corrosion (metal substrate), erosion, chemical attack, exposure to temperature or moisture	"AMP XI.M43, "High Density Polyethylene (HDPE) CFRP Repaired Piping"	No	Not Applicable. There are no HDPE, CFRP underground piping, piping components in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-134	Steel, SS, copper alloy piping, piping components, and heat exchanger components exposed to raw water (for components not covered by U.S. Nuclear Regulatory Commission (NRC) Generic Letter (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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage flow blockage and loss of material of the copper alloy heat exchanger components exposed to raw water in the Fire Detection and Protection System. Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel, cast iron, copper alloy, and stainless steel heat exchanger components, piping, piping components, tanks, and valve bodies exposed to raw water in the Compressed Air Systems, Makeup Demineralizer System, and Sampling System. Flow blockage due to fouling in carbon steel, cast iron, copper alloy, and stainless steel heat exchanger components, piping, piping components, tanks, and valve bodies exposed to raw water in the Compressed Air Systems, Makeup Demineralizer System, and Sampling System is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-135	Steel, SS 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 External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon steel drip pans exposed to waste water in the Feedwater/High Pressure Coolant Injection System.
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. The Fire Water System (B.2.1.16) program will be used to manage loss of material of the carbon steel and cast iron piping, piping components, pump casings, tanks, and valve bodies exposed to air - indoor, uncontrolled in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.16) program implementation.
3.3.1-137	Steel, SS, 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, SS only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program has been substituted and will be used to manage loss of material of the stainless steel components exposed to raw water in the Screen and Pump House Building.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water, air-dry, air, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program will be used to manage loss of coating or lining integrity of the carbon steel (with internal coatings) and cast iron (with internal coatings) heat exchanger components, piping, piping components, tanks, and valve bodies exposed to closed cycle cooling water, lubricating oil, raw water, treated water, and waste water in the City Water System, Compressed Air Systems, Fire Detection and Protection System, Makeup Demineralizer System, Spent Fuel Pool Cooling and Storage System, and Turbine Building Closed Loop Cooling System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program has been substituted and will be used to manage loss of coating or lining integrity of the carbon steel (with internal coatings) tanks exposed to lubricating oil and treated water in the Makeup Demineralizer System and Reactor Water Cleanup System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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, air-dry, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program will be used to manage loss of material of the carbon steel (with internal coatings) and cast iron (with internal coatings) heat exchanger components, piping, piping components, tanks, and valve bodies exposed to closed cycle cooling water, lubricating oil, raw water, treated water, and waste water in the City Water System, Compressed Air Systems, Fire Detection and Protection System, Makeup Demineralizer System, Spent Fuel Pool Cooling and Storage System, and Turbine Building Closed Loop Cooling System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program has been substituted and will be used to manage loss of material of the carbon steel (with internal coatings) tanks exposed to lubricating oil and treated water in the Makeup Demineralizer System and Reactor Water Cleanup System.
3.3.1-140	Gray cast iron, ductile iron, malleable 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. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program will be used to manage loss of material of the cast iron (with internal coatings) piping, piping components, and valve bodies exposed to raw water in the Fire Detection and Protection System and Makeup Demineralizer System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-141	This Item Number is not listed in NUREG-2192.				
3.3.1-142	SS, 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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel bolting and stainless steel bolting exposed to raw water and treated water in the Circulating Water System, Emergency Diesel Generator System, Fire Detection and Protection System, Service Water System, and Spent Fuel Pool Cooling and Storage System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program has been substituted and will be used to manage loss of material of the stainless steel bolting and concrete elements exposed to raw water in the Screen and Pump House Building.
3.3.1-143	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-144	SS, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no stainless steel or aluminum piping, piping components, tanks exposed to soil or concrete in Auxiliary Systems. There are no steel piping, piping components, tanks exposed to concrete in Auxiliary Systems. Cracking due to SCC in carbon steel and cast iron exposed to soil is not an applicable aging effect/mechanism since soil is not a carbonate/bicarbonate environment.
3.3.1-145	SS closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage cracking of the stainless steel closure bolting exposed to air - indoor, uncontrolled and air - outdoor in the Circulating Water System, Containment Systems, Control Room HVAC System, Fire Detection and Protection System, Liquid Poison System, Makeup Demineralizer System, Reactor Water Cleanup, Service Water System, Turbine Building HVAC System, and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-146	SS 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of stainless steel hoses exposed to the environment of underground in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.3.
3.3.1-147	Nickel-alloy, nickel-alloy cladding piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the nickel alloy heat exchanger components exposed to closed cycle cooling water in the Sampling System.
3.3.1-148	This Item Number is not listed in NUREG-2192.				
3.3.1-149	Fiberglass piping, piping components, ducting, ducting components exposed to air – outdoor	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no fiberglass piping, piping components, ducting, ducting components exposed to air - outdoor in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-150	Fiberglass piping, piping components, ducting, ducting components exposed to air	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no fiberglass piping, piping components, ducting, ducting components exposed to air in Auxiliary Systems.
3.3.1-151	SS, 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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage reduction of heat transfer of the copper alloy and stainless steel heat exchanger components exposed to air - outdoor in the Containment Systems.
3.3.1-152	This Item Number is not listed in NUREG-2192.				
3.3.1-153	This Item Number is not listed in NUREG-2192.				
3.3.1-154	This Item Number is not listed in NUREG-2192.				
3.3.1-155	SS piping, piping components, and tanks exposed to waste water >60°C (>140°F)	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage cracking of the stainless steel piping, piping components exposed to waste water > 140°F in the Main Generator and Auxiliary System.
3.3.1-156	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.16) program will be used to manage loss of material of the carbon steel piping, piping components and valve bodies exposed to air - outdoor in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.16) program implementation.
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. There are no nickel-alloy piping, piping components heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water in Auxiliary Systems.
3.3.1-159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no fiberglass piping, piping components, ducting, ducting components exposed to air in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. The Closed Treated Water Systems (B.2.1.12), Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24), and Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage cracking of the copper alloy with 15% zinc or >heat exchanger components and valve bodies exposed to closed cycle cooling water, raw water, and waste water in Circulating Water, Emergency Diesel Generator, Radioactive Waste, Service Water, and Turbine Building Closed Loop Cooling Systems. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program has been substituted to manage cracking of copper alloy with 15% zinc or > valves in the City Water System and heat exchanger components in the Fire Detection and Protection System, exposed to raw water. Cracking of copper alloy with 15% zinc or > exposed to closed cycle cooling water in the Compressed Air, Control Room HVAC, Radioactive Waste, Reactor Building Closed Loop Cooling, Reactor Water Cleanup, Spent Fuel Pool Cooling and Storage, Turbine Building Closed Loop Cooling, and Feedwater/High Pressure Coolant Injection Systems isn't an applicable aging effect since the water environment in these systems is pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage reduction of heat transfer of the copper alloy heat exchanger components exposed to condensation in the Compressed Air Systems and Emergency Diesel Generator System.
3.3.1-162	This Item Number is not listed in NUREG-2192.				
3.3.1-163	This Item Number is not listed in NUREG-2192.				
3.3.1-164	This Item Number is not listed in NUREG-2192.				
3.3.1-165	This Item Number is not listed in NUREG-2192.				
3.3.1-166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There are no copper alloy piping, piping components exposed to concrete in Auxiliary Systems.
3.3.1-167	Zinc piping components exposed to air-indoor controlled, air – indoor uncontrolled	None	None	No	Consistent with NUREG-2191.
3.3.1-168	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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"	No	Not Applicable. There are no steel, copper alloy piping, piping components exposed to steam in Auxiliary Systems.
3.3.1-170	SS piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry"	No	Not Applicable. There are no stainless steel piping, piping components exposed to steam in Auxiliary Systems.
3.3.1-171	This Item Number is not listed in NUREG-2192.				
3.3.1-172	PVC piping, piping components exposed to air outdoor	Reduction in impact strength due to photolysis	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no PVC piping, piping components exposed to air outdoor in Auxiliary Systems.
3.3.1-173	This Item Number is not listed in NUREG-2192.				
3.3.1-174	This Item Number is not listed in NUREG-2192.				
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 radiation, temperature, or moisture; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no 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 in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-176	Fiberglass piping, piping components, tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no 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 in Auxiliary Systems.
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 with exceptions. The Buried and Underground Piping and Tanks (B.2.1.27) program will be used to manage loss of material due to peeling, delamination, wear of the fiberglass tanks exposed to soil in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks (B.2.1.27) program implementation.
3.3.1-178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not Applicable. There are no fiberglass piping and piping components exposed to concrete in Auxiliary Systems,

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Fire Protection (B.2.1.15) and Masonry Walls (B.2.1.32) program will be used to manage cracking and loss of material of the concrete block fire barriers exposed to air - indoor, uncontrolled in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Masonry Walls (B.2.1.32) program implementation.
3.3.1-180	This Item Number is not listed in NUREG-2192.				
3.3.1-181	Titanium piping, piping components exposed to condensation	None	None	No	Not Applicable. There are no titanium piping, piping components exposed to condensation in Auxiliary Systems.
3.3.1-182	Nonmetallic 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 Used. Reduced thermal insulation resistance due to moisture intrusion in nonmetallic thermal insulation is addressed in Item Number 3.4.1-064 in the Structural Commodity Group.
3.3.1-183	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not Applicable. There are no PVC piping, piping components, tanks exposed to concrete in Auxiliary Systems.
3.3.1-185	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water in Auxiliary Systems.
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	Not Applicable. There are no 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 in Auxiliary Systems. See Subsection 3.3.2.2.8.
3.3.1-187	This Item Number is not listed in NUREG-2192.				
3.3.1-188	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the aluminum alloy ducting and components, piping, piping components, pump casings, spray nozzles, and valve bodies exposed to air - indoor, uncontrolled, air - outdoor, condensation, and raw water (non-potable) in the Compressed Air Systems, Control Room HVAC System, Emergency Diesel Generator System, Fire Detection and Protection System, Sampling System, and Spent Fuel Pool Cooling and Storage System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.8.
3.3.1-190	This Item Number is not listed in NUREG-2192.				
3.3.1-191	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not Applicable. There are no aluminum underground piping, piping components, tanks in Auxiliary Systems. See Subsection 3.3.2.2.8.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage long-term loss of material of the carbon steel, cast iron, and galvanized steel boiler casings, drip pans, fire hydrants, heat exchanger components, pump casings, tanks and valve bodies exposed to raw water, treated water, and waste water in the Circulating Water System, City Water System, Compressed Air Systems, Containment Systems, Electric Steam Boiler System, Emergency Diesel Generator System, Fire Detection and Protection System, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Reactor Building Closed Loop Cooling System, Reactor Building HVAC System, Reactor Water Cleanup, Sampling System, Service Water System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, Turbine Building Closed Loop Cooling System, Turbine Building HVAC System, Control Rod Drive System, Condensate and Condensate Transfer System, Feedwater/High Pressure Coolant Injection System, and Main Turbine and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-194	PVC, CFRP piping, piping components, and tanks exposed to soil	Cracking, blistering, loss of material due to wear, general corrosion (metal substrate), erosion, chemical attack, exposure to moisture	AMP XI.M41, "Buried and Underground Piping and Tanks" or AMP XI.M43, "High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping"	No	Not Applicable. There are no PVC, CFRP piping, piping components, and tanks exposed to soil in Auxiliary Systems.
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	Consistent with NUREG-2191 with exceptions. The Fire Water System (B.2.1.16) program will be used to manage cracking, flow blockage, and loss of material of the concrete piping, piping components exposed to raw water in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B.2.1.16) program implementation.
3.3.1-196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering, loss of material due to exposure to radiation, temperature, or moisture; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no HDPE piping, piping components exposed to raw water, treated water, raw water (potable) in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the leakage boundary carbon steel and cast iron piping, piping components, pump casings, and valve bodies exposed to air - indoor, uncontrolled in the Fire Detection and Protection System.
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel, cast iron, and stainless steel leakage boundary piping, piping components, pump casings, and valve bodies exposed to raw water in the Fire Detection and Protection System.
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. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program will be used to manage cracking, loss of material, and loss of preload of the carbon and low alloy steel bolting exposed to air - indoor, uncontrolled in the Cranes, Hoists, and Refueling Equipment System.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-200	This Item Number is not listed in NUREG-2192.				
3.3.1-201	This Item Number is not listed in NUREG-2192.				
3.3.1-202	SS piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no stainless steel piping, piping components exposed to concrete in Auxiliary Systems. See Subsection 3.3.2.2.9.
3.3.1-203	SS; steel with SS cladding, steel, 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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the stainless steel cladding, cast austenitic stainless steel, nickel alloy, and SS accumulators, electric heaters, flexible connections, flow devices, heat exchanger components, piping, piping components, pump casings, strainer (elements), tanks, and valve bodies exposed to sodium pentaborate solution and treated water in the Electric Steam Boiler System, Liquid Poison System, Makeup Demineralizer System, Radioactive Waste System, Reactor Water Cleanup, Sampling System, Shutdown Cooling System, Spent Fuel Pool Cooling and Storage System, and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-204	This Item Number is not listed in NUREG-2192.				
3.3.1-205	Insulated SS 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the insulated stainless steel piping, piping components, pump casings, and valve bodies exposed to condensation in the Control Room HVAC System and Service Water System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.3.
3.3.1-206	This Item Number is not listed in NUREG-2192.				
3.3.1-207	SS, copper alloy, titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no stainless steel, copper alloy, titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13) in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. There are no 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) in Auxiliary Systems.
3.3.1-209	This Item Number is not listed in NUREG-2192.				
3.3.1-210	HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking, blistering, loss of material due to exposure to radiation, temperature, or moisture; flow blockage due to fouling	"AMP XI.M43, "High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping"	No	Not Applicable. There are no HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in Auxiliary Systems.
3.3.1-211	This Item Number is not listed in NUREG-2192.				
3.3.1-212	This Item Number is not listed in NUREG-2192.				
3.3.1-213	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-214	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in Auxiliary Systems.
3.3.1-215	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water in Auxiliary Systems.
3.3.1-216	SS fire water storage tanks exposed to air, condensation, soil, concrete	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no stainless steel fire water storage tanks exposed to air, condensation, soil, concrete in Auxiliary Systems.
3.3.1-217	This Item Number is not listed in NUREG-2192.				
3.3.1-218	SS fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion, MIC (water and soil environment only)	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water in Auxiliary Systems.
3.3.1-219	SS piping, piping components exposed to steam	Cracking due to SCC	AMP XI.M2, "Water Chemistry"	No	Not Applicable. There are no stainless steel piping, piping components exposed to steam in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-220	This Item Number is not listed in NUREG-2192.				
3.3.1-221	This Item Number is not listed in NUREG-2192.				
3.3.1-222	SS, 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the stainless steel accumulators and tanks exposed to air - indoor, uncontrolled and condensation in the Radioactive Waste System and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 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	Not Applicable. There are no aluminum underground piping, piping components, tanks in Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-224	This Item Number is not listed in NUREG-2192.				
3.3.1-225	This Item Number is not listed in NUREG-2192.				
3.3.1-226	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete in Auxiliary Systems.
3.3.1-227	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks")	Loss of material due to pitting, crevice corrosion exposed to air, condensation	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	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-228	SS, 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	Not Applicable. There are no 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 Auxiliary Systems. See Subsection 3.3.2.2.4.
3.3.1-229	SS tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete in Auxiliary Systems.
3.3.1-230	SS tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-231	SS 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	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in Auxiliary Systems. See Subsection 3.3.2.2.3.
3.3.1-232	Insulated SS, 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the insulated stainless steel piping, piping components, pump casings and valve bodies exposed to condensation in the Control Room HVAC System and Service Water System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.4.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not Applicable. There are no insulated aluminum piping, piping components, tanks exposed to air, condensation in Auxiliary Systems. See Subsection 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the aluminum alloy ducting and components, piping, piping components, pump casings, spray nozzles, and valve bodies exposed to air - indoor, uncontrolled, air - outdoor, and condensation in the Compressed Air Systems, Control Room HVAC System, Emergency Diesel Generator System, Fire Detection and Protection System, Sampling System, and Spent Fuel Pool Cooling and Storage System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.10.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Compressed Air Monitoring (B.2.1.14) program will be used to manage loss of material of the aluminum alloy, carbon steel, cast iron, copper alloy, and stainless steel accumulators, piping, piping components, strainer (elements), tanks, and valve bodies exposed to air - dry in the Compressed Air Systems and Fire Detection and Protection System.
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"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to treated water in Auxiliary Systems.
3.3.1-237	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not Applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water in Auxiliary Systems.
3.3.1-238	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to closed-cycle cooling water in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-239	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not Applicable. There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water in Auxiliary Systems.
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	Not Applicable. There are no aluminum heat exchanger components exposed to waste water in Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-241	SS, 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the nickel alloy and stainless steel heat exchanger components exposed to air - indoor, uncontrolled in the Sampling System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.3.2.2.4.
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	Not Applicable. There are no aluminum heat exchanger components exposed to air, condensation in Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-243	This Item Number is not listed in NUREG-2192.				
3.3.1-244	SS, nickel-alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage cracking of the cast austenitic stainless steel, nickel alloy, and stainless steel expansion joints, flexible connections, flow devices, heat exchanger components, pump casings, and valve bodies exposed to treated water > 140°F and treated water > 482°F in the Electric Steam Boiler System, Reactor Water Cleanup, Sampling System, Shutdown Cooling System, Control Rod Drive System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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	Not Applicable. There are no insulated aluminum piping, piping components, tanks exposed to air, condensation in Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-246	SS, 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the stainless steel hoses exposed to the environment of underground in the Fire Detection and Protection System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the aluminum alloy pump casings exposed to raw water in the Sampling System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 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. There are no aluminum piping, piping components, tanks exposed to air with borated water leakage in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel heat exchanger components exposed to condensation in the Radioactive Waste System.
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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the carbon steel tanks exposed to lubricating oil (waste oil) in the Emergency Diesel Generator System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation.
3.3.1-251	This Item Number is not listed in NUREG-2192.				
3.3.1-252	Aluminum piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no aluminum piping, piping components exposed to soil, concrete in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-253	PVC, CFRP piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Cracking, blistering, loss of material due to wear, tearing, delamination, void, debonding, chemical attack and exposure to moisture; flow blockage due to fouling, delamination, debonding, or tearing	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M43, "High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) and Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage loss of material due to wear of the PVC accumulators, piping, piping components, pump casings, and valve bodies exposed to raw water and waste water in the Circulating Water System, Makeup Demineralizer System, and Service Water System. Flow blockage due to fouling in PVC accumulators, piping, piping components, pump casings, and valve bodies exposed to raw water and waste water in the Circulating Water System, Makeup Demineralizer System, and Service Water System is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. There are no aluminum heat exchanger components exposed to air, condensation in Auxiliary Systems. See Subsection 3.3.2.2.8.
3.3.1-255	Metallic fire damper housings exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC (SS only)	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.15) program will be used to manage cracking and loss of material of the galvanized steel and stainless steel fire barriers (damper housings and penetration seals) exposed to air - indoor, uncontrolled and condensation in the Fire Detection and Protection System.
3.3.1-256	This Item Number is not listed in NUREG-2192.				

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-257	Steel, SS, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage reduction of heat transfer of the cast iron and copper alloy heat exchanger components exposed to lubricating oil in the Control Rod Drive System, Condensate and Condensate Transfer System, Emergency Diesel Generator System, Fire Detection and Protection System, and Service Water System.
3.3.1-258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Used. There are no fiberglass, HDPE piping, piping components exposed to waste water in Auxiliary Systems. Flow blockage due to fouling in elastomer expansion joints in the Radioactive Waste System is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply. Flow blockage due to fouling in metallic components with a pressure boundary function in the Compressed Air Systems and Radioactive Waste System is addressed in item Number 3.3.1-091 for cast iron and carbon steel and in Item Number 3.3.1-095 for copper alloy and stainless steel.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. Flow blockage due to fouling in aluminum pump casings exposed to raw water in the Sampling System is not an applicable aging effect because these components only have a leakage boundary intended function where flow blockage does not apply.
3.3.1-260	Metallic heating, ventilation and air conditioning systems 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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon and low alloy steel ducting closure bolting exposed to air - indoor, uncontrolled in the Control Room HVAC System and Reactor Building HVAC System. Ductwork closure bolting is not subject to significant thermal effects or preloads. Ductwork closure bolting function is primarily to maintain the duct structural assembly. Since ductwork closure bolting does not perform a significant pressure boundary function, loss of preload is not considered a significant aging effect.
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, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water, raw water in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-262	Titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water in Auxiliary Systems.

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 (Inspection of Internal Surfaces only)	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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will manage cracking or blistering, flow blockage, hardening or loss of strength due to polymeric degradation, loss of material due to peeling, delamination, and wear of the polymer piping elements, piping, piping components, strainer (elements), tanks, and valve bodies exposed to air - indoor, uncontrolled, condensation, raw water, treated water, and waste water in the Circulating Water System, Compressed Air Systems, Fire Detection and Protection System, Makeup Demineralizer System, Reactor Water Cleanup, Sampling System, and Service Water System. The Fire Protection (B.2.1.15) program has been substituted to manage cracking or blistering, hardening or loss of strength due to polymeric degradation, loss of material due to peeling, delamination, and wear in polymer fire barriers exposed to air - indoor, uncontrolled in the Fire Detection and Protection System. The Buried and Underground Piping and Tanks (B.2.1.27) program has been substituted to manage cracking or blistering, hardening or loss of strength due to polymeric degradation, loss of material due to peeling, delamination, and wear in polymer piping, piping components exposed to soil and an underground environment in the Fire Detection and Protection System.
3.3.1-264	Steel piping, piping components, and tanks exposed to treated	Long-term loss of material due to general corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, One-Time Inspection"	No	Not Used. There are no steel piping, piping components, and tanks exposed to sodium pentaborate solution in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
	water, sodium pentaborate solution.				Long-term loss of material due to general corrosion in carbon steel and cast iron components exposed to treated water in the Auxiliary Systems is addressed in Item Number 3.3.1-193.
3.3.1-265	Steel heat exchanger tubes exposed to fuel oil	Reduction of heat transfer due to fouling	XI.M30, "Fuel Oil Chemistry"	No	Not Applicable. There are no steel heat exchanger tubes exposed to fuel oil in Auxiliary Systems.
3.3.1-266	This Item Number is not listed in NUREG-2192.				
3.3.1-267	Subliming compound fireproofing/fire barriers (Thermo-lag®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air	Loss of material due to abrasion, flaking, vibration; cracking/delamination due to chemical reaction, settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, "Fire Protection"	No	Not Applicable. There are no subliming compound fireproofing/fire barriers (Thermo-lag®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air in Auxiliary Systems.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-268	Cementitious coating fireproofing/fire barriers (Pyrocrete, BIO™ K-10 Mortar, Cafecote, and other similar materials) exposed to air	Loss of material due to abrasion, exfoliation, elevated temperature, flaking, spalling; cracking/ delamination due to chemical reaction, elevated temperature, settlement, vibration; change in material properties due to elevated temperature, gamma irradiation exposure; separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.15) program will be used to manage change in material properties, cracking, loss of material, and separation of the cementitious fireproofing fire barriers exposed to air - indoor, uncontrolled in the Fire Detection and Protection System.
3.3.1-269	Silicate fireproofing/fire barriers (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials) exposed to air	Loss of material due to abrasion, flaking; cracking/ delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.1.15) program will be used to manage change in material properties, cracking, loss of material, and separation of the silicate fireproofing fire barriers exposed to air - indoor, uncontrolled in the Fire Detection and Protection System.

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37225	Accumulator (Chemical Addition Pulsation Damper)	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37226	Accumulator (Chemical Addition Pulsation Damper)	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
35998	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
35999	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
37084	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
37085	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
37086	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
39196	Bolting (Traveling Screens)	Structural Support	Stainless Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	D
39197	Bolting (Traveling Screens)	Structural Support	Stainless Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	D
37232	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
37233	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
37229	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Raw Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.AP-75	3.3.1-085	A
37230	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Raw Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.AP-76	3.3.1-096	A
37454	Flexible Connection	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
37455	Flexible Connection	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37456	Flexible Connection	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
37234	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Shell Side Components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 1
38959	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Shell Side Components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
37235	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Shell Side Components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
37237	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Shell Side Components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-66	3.3.1-072	B
37238	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
37489	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37239	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37490	Heat Exchanger – (Condenser Waterbox Priming Pump Cooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	D
37444	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
37491	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
37445	Hoses	Leakage Boundary (Spatial)	Elastomers	Lubricating Oil (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-677	3.3.1-085	A
37446	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37447	Piping elements	Leakage Boundary (Spatial)	Glass	Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
37240	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37241	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.C1.AP-127	3.3.1-097	A
37492	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37242	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
39236	Piping, piping components	Leakage Boundary (Spatial)	Concrete	Air - Indoor, Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.1.23)			G, 2
39237	Piping, piping components	Leakage Boundary (Spatial)	Concrete	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)			G, 2
39238	Piping, piping components	Leakage Boundary (Spatial)	Concrete	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-250	3.3.1-030	A
39239	Piping, piping components	Leakage Boundary (Spatial)	Concrete	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-250	3.3.1-030	A
37495	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
37496	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
37248	Piping, piping components	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37249	Piping, piping components	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
37252	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
37253	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
37254	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37258	Pump Casing (Circulating Water Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37259	Pump Casing (Circulating Water Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37257	Pump Casing (Circulating Water Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37260	Pump Casing (Circulating Water Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
37270	Pump Casing (Condenser Waterbox Priming Pump)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37272	Pump Casing (Condenser Waterbox Priming Pump)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37271	Pump Casing (Condenser Waterbox Priming Pump)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37462	Pump Casing (Deposit Penetrant Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
37463	Pump Casing (Deposit Penetrant Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
37464	Pump Casing (Deposit Penetrant Pump)	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
37465	Pump Casing (Dispersant Pump)	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37466	Pump Casing (Dispersant Pump)	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
37261	Pump Casing (Hydraulic Pump)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37262	Pump Casing (Hydraulic Pump)	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.C1.AP-127	3.3.1-097	A
37263	Pump Casing (Screen Wash Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37266	Pump Casing (Screen Wash Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37265	Pump Casing (Screen Wash Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37267	Pump Casing (Screen Wash Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
37460	Pump Casing (Sodium Bisulfite Pump)	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37461	Pump Casing (Sodium Bisulfite Pump)	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
37467	Pump Casing (Sodium Bromide Pump)	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37468	Pump Casing (Sodium Bromide Pump)	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
37268	Pump Casing (Sodium Hypochlorite Pump)	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37269	Pump Casing (Sodium Hypochlorite Pump)	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
37273	Tanks (100 Gallon Reservoir)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37274	Tanks (100 Gallon Reservoir)	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.C1.AP-127	3.3.1-097	A
37275	Tanks (Condenser Waterbox Priming Sump Volume Chamber)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37277	Tanks (Condenser Waterbox Priming Sump Volume Chamber)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37276	Tanks (Condenser Waterbox Priming Sump Volume Chamber)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37497	Tanks (Deposit Penetrant Tank)	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37301	Tanks (Deposit Penetrant Tank)	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37498	Tanks (Deposit Penetrant Tank)	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37499	Tanks (Deposit Penetrant Tank)	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
37278	Tanks (Deposit Penetrant Tank)	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
37500	Tanks (Deposit Penetrant Tank)	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
37297	Tanks (Moisture Separator)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37299	Tanks (Moisture Separator)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37298	Tanks (Moisture Separator)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37501	Tanks (Sodium Bromide Tank)	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37300	Tanks (Sodium Bromide Tank)	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37502	Tanks (Sodium Bromide Tank)	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37503	Tanks (Sodium Bromide Tank)	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
37302	Tanks (Sodium Bromide Tank)	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37504	Tanks (Sodium Bromide Tank)	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
37505	Traveling Water Screens (Revolving Screen)	Filter	Stainless Steel	Raw Water (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
37303	Traveling Water Screens (Revolving Screen)	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
37243	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37244	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.C1.AP-127	3.3.1-097	A
37506	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37245	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37469	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37449	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37448	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37450	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
37255	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
37256	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
37251	Valve Body	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37250	Valve Body	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
37451	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37452	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
37453	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-1 Circulating Water System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.
2. The aging effects on concrete pipe exposed to indoor air include cracking and loss of material. These aging effects are managed by the External Surfaces Monitoring of Mechanical Components (B.2.1.23) program.

Table 3.3.2-2 City Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38215	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
38216	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38237	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
38238	Piping elements	Leakage Boundary (Spatial)	Glass	Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
38223	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38225	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
38224	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3.1-088	A
39030	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C3.A-400b	3.3.1-127	A
38226	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38228	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-271	3.3.1-093	A
39031	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C3.A-400b	3.3.1-127	A
38220	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
38222	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B

Table 3.3.2-2 City Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38221	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3.1-088	A
38250	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38251	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38249	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3.1-088	A
38248	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Raw Water > 140°F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 1
38252	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Raw Water > 140°F (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3.1-088	A
38244	Pump Casing (Heating System Recirculation Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38270	Pump Casing (Heating System Recirculation Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
38247	Pump Casing (Heating System Recirculation Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3.1-088	A
38246	Pump Casing (Heating System Recirculation Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
38335	Pump Casing (Hot Water Recirculating Pumps)	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38334	Pump Casing (Hot Water Recirculating Pumps)	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-271	3.3.1-093	A

Table 3.3.2-2 City Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38236	Tanks (City Water Hot Water Heaters)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38235	Tanks (City Water Hot Water Heaters)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
38234	Tanks (City Water Hot Water Heaters)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
38232	Tanks (City Water Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38268	Tanks (City Water Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-401	3.2.1-072	B
38243	Tanks (City Water Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-414	3.2.1-073	B
38231	Tanks (City Water Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
38230	Tanks (City Water Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
38260	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-2 City Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38257	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
38259	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3.1-088	A
38256	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38253	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
38255	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3.1-088	A
38254	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
38266	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 3
38271	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-473b	3.3.1-160	E, 2
38261	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-271	3.3.1-093	A
38264	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-47	3.3.1-072	B
38267	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38262	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-271	3.3.1-093	A

Table 3.3.2-2 City Water System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) aging management program is used to manage cracking of stainless steel in a potable raw water environment at temperatures above 140 degrees F.
2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) aging management program is used to manage cracking of copper alloy with 15% zinc or more in a potable raw water environment.
3. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38855	Accumulator (Scram Air Volume)	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38853	Accumulator (Scram Air Volume)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38854	Accumulator (Scram Air Volume)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
37822	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
37823	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38557	Heat Exchanger – (Breathing Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
38768	Heat Exchanger – (Breathing Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
38767	Heat Exchanger – (Breathing Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
38766	Heat Exchanger – (Breathing Air Compressor Aftercooler) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
38765	Heat Exchanger – (Breathing Air Compressor Aftercooler) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	C
38794	Heat Exchanger – (Breathing Air Compressor Intercooler) Shell Side Components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
38793	Heat Exchanger – (Breathing Air Compressor Intercooler) Shell Side Components	Leakage Boundary (Spatial)	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	C
38795	Heat Exchanger – (Breathing Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38865	Heat Exchanger – (Breathing Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
38864	Heat Exchanger – (Breathing Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
38866	Heat Exchanger – (Breathing Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	D
38565	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39067	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
38568	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
38774	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
38775	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-43	3.3.1-072	D
38776	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.A-473a	3.3.1-160	I, 1
38772	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38777	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
38773	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38769	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
38771	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tube Side Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	C
38573	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	A
38575	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Condensation (Internal)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-565	3.3.1-161	A
38868	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
38869	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-43	3.3.1-072	D
38870	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.A-473a	3.3.1-160	I, 1
38576	Heat Exchanger – (Instrument Air Compressor #11 & 12 Aftercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38577	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Shell Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
38578	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Shell Side Components	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	C
39068	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
38782	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38581	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Sheet	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	C
38783	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39069	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
38784	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
38873	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tube Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	D
38585	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	A
38586	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-565	3.3.1-161	A
38874	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
38875	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-43	3.3.1-072	D
38876	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 1
38877	Heat Exchanger – (Instrument Air Compressor #11 & 12 Intercooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
38594	Heat Exchanger – (Service Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39070	Heat Exchanger – (Service Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38879	Heat Exchanger – (Service Air Compressor Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
38785	Heat Exchanger – (Service Air Compressor Aftercooler) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
38786	Heat Exchanger – (Service Air Compressor Aftercooler) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	C
38723	Heat Exchanger – (Service Air Compressor Intercooler) Shell Side Components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
38724	Heat Exchanger – (Service Air Compressor Intercooler) Shell Side Components	Leakage Boundary (Spatial)	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	C
38880	Heat Exchanger – (Service Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39071	Heat Exchanger – (Service Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
38883	Heat Exchanger – (Service Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
38882	Heat Exchanger – (Service Air Compressor Intercooler) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	D
38760	Hoses	Pressure Boundary	Elastomers	Air - Dry (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-504	3.3.1-085	A
38756	Hoses	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
38762	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38763	Piping elements	Leakage Boundary (Spatial)	Glass	Waste Water (Internal)	None	None	VII.J.AP-277	3.3.1-119	A
38607	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38606	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38605	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38801	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38804	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38803	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38805	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E5.A-547	3.3.1-072	B
38809	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38610	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.A-451a	3.3.1-189	B
38611	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-763a	3.3.1-234	B
38885	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38613	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38811	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38614	Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38617	Piping, piping components	Pressure Boundary	Cast Iron	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38618	Piping, piping components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38927	Piping, piping components	Pressure Boundary	Cast Iron	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38807	Piping, piping components	Pressure Boundary	Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38806	Piping, piping components	Pressure Boundary	Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38808	Piping, piping components	Pressure Boundary	Cast Iron	Waste Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E5.A-547	3.3.1-072	B
38621	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38619	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 4
38620	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38624	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Dry (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38622	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38886	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38629	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38887	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38888	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38627	Piping, piping components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38628	Piping, piping components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38812	Piping, piping components	Pressure Boundary	Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.A-712	3.3.1-167	A
38813	Piping, piping components	Pressure Boundary	Zinc	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 3
38814	Piping, piping components	Structural Integrity (Attached)	Aluminum Alloy	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38816	Piping, piping components	Structural Integrity (Attached)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.A-451a	3.3.1-189	B
38817	Piping, piping components	Structural Integrity (Attached)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-763a	3.3.1-234	B
38633	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38889	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38890	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38642	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or More	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38891	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 4
38892	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38639	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Air - Dry (Internal)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38637	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38638	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38893	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38894	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38895	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38896	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38923	Silencer / Muffler	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38924	Silencer / Muffler	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38925	Silencer / Muffler	Structural Support	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38926	Silencer / Muffler	Structural Support	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38727	Strainer (Element)	Filter	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38898	Strainer (Element)	Filter	Copper Alloy with less than 15% Zinc	Air - Dry (External)	None	None	VII.J.AP-144	3.3.1-114	A
38897	Strainer (Element)	Filter	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
38901	Strainer (Element)	Filter	Polymer	Condensation (External)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A
38928	Strainer (Element)	Filter	Polymer	Condensation (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38899	Strainer (Element)	Filter	Polymer	Condensation (External)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A
38900	Strainer (Element)	Filter	Polymer	Condensation (External)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A
38649	Strainer (Element)	Filter	Stainless Steel	Air - Dry (External)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38902	Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38903	Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38823	Tanks (Afterfilters)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Air - Dry (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.D.A-416	3.3.1-138	B
38824	Tanks (Afterfilters)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Air - Dry (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.D.A-414	3.3.1-139	B
38820	Tanks (Afterfilters)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38821	Tanks (Afterfilters)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-401	3.2.1-072	B
38822	Tanks (Afterfilters)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-414	3.2.1-073	B

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38655	Tanks (Breathing Air Aftercooler Moisture Separator)	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38656	Tanks (Breathing Air Aftercooler Moisture Separator)	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38657	Tanks (Breathing Air Receiver)	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38659	Tanks (Breathing Air Receiver)	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38662	Tanks (Containment Spray System Air Test Receiver)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38663	Tanks (Containment Spray System Air Test Receiver)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38830	Tanks (Feedwater Flow Control Valve Receiver)	Structural Integrity (Attached)	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38829	Tanks (Feedwater Flow Control Valve Receiver)	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38669	Tanks (Instrument Air Aftercooler Moisture Separators)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38670	Tanks (Instrument Air Aftercooler Moisture Separators)	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38667	Tanks (Instrument Air Dryer Chambers)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38668	Tanks (Instrument Air Dryer Chambers)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38904	Tanks (Instrument Air Receiver #11)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38674	Tanks (Instrument Air Receiver #11)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38905	Tanks (Instrument Air Receiver #12)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38676	Tanks (Instrument Air Receiver #12)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38906	Tanks (Reactor Building Door Seal Receiver)	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38832	Tanks (Reactor Building Door Seal Receiver)	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38825	Tanks (Service Air Aftercooler Moisture Separator)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38826	Tanks (Service Air Aftercooler Moisture Separator)	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38828	Tanks (Service Air Receiver)	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38827	Tanks (Service Air Receiver)	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38679	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38604	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38602	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38682	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38998	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-272	3.3.1-095	A
38833	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38835	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.A-451a	3.3.1-189	B
38836	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-763a	3.3.1-234	B
38907	Valve Body	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38685	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38686	Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38908	Valve Body	Pressure Boundary	Cast Iron	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38910	Valve Body	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38909	Valve Body	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38691	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38689	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 4
38690	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38929	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Dry (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38911	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38912	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38931	Valve Body	Pressure Boundary	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
38932	Valve Body	Pressure Boundary	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
38933	Valve Body	Pressure Boundary	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
38934	Valve Body	Pressure Boundary	Polymer	Condensation (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A
38937	Valve Body	Pressure Boundary	Polymer	Condensation (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A
38935	Valve Body	Pressure Boundary	Polymer	Condensation (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38936	Valve Body	Pressure Boundary	Polymer	Condensation (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-797b	3.3.1-263	A
38915	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38916	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38913	Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38914	Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38698	Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38699	Valve Body	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38700	Valve Body	Structural Integrity (Attached)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38701	Valve Body	Structural Integrity (Attached)	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3.1-055	A
38702	Valve Body	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or More	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
38917	Valve Body	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 4
38918	Valve Body	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38930	Valve Body	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Air - Dry (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38705	Valve Body	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38706	Valve Body	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
38919	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38920	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B
38921	Valve Body	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3.1-004	B
38922	Valve Body	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3.1-006	B

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.
2. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
3. The aging effect on zinc with an internal environment of condensation includes loss of material. This aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program.

Table 3.3.2-3 Compressed Air Systems Summary of Aging Management Evaluation

4. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-4 Containment Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36083	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
36084	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38857	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
38858	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
38859	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38862	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
38861	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
38860	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38730	Heat Exchanger – (Ambient Vaporizer) Fins	Heat Transfer	Copper Alloy with less than 15% Zinc	Air - Outdoor (External)	Reduction of Heat Transfer	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3.1-151	C
38731	Heat Exchanger – (Ambient Vaporizer) Tubes	Heat Transfer	Stainless Steel	Air - Outdoor (External)	Reduction of Heat Transfer	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3.1-151	A
37968	Heat Exchanger – (Ambient Vaporizer) Tubes	Heat Transfer	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	C
38501	Heat Exchanger – (Ambient Vaporizer) Tubes	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	D
38502	Heat Exchanger – (Ambient Vaporizer) Tubes	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	D
38500	Heat Exchanger – (Ambient Vaporizer) Tubes	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	C
37897	Heat Exchanger – (Drywell Air Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
37970	Heat Exchanger – (Drywell Air Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	A
38745	Heat Exchanger – (Drywell Air Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-4 Containment Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38744	Heat Exchanger – (Drywell Air Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	A
37914	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37920	Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37922	Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-26	3.3.1-055	A
37909	Piping, piping components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
37975	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.A-439	3.3.1-193	B
37974	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
37933	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 1
38513	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
37900	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
37967	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
37972	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
37902	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
37934	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37935	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37948	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37949	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B

Table 3.3.2-4 Containment Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38515	Piping, piping components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
38516	Piping, piping components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37903	Piping, piping components	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
37915	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37923	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-26	3.3.1-055	A
37911	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
38747	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38748	Piping, piping components	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
37936	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37937	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37950	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37951	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
38489	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
38490	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37904	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
37946	Rupture Disks	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37947	Rupture Disks	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B

Table 3.3.2-4 Containment Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37944	Rupture Disks	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37945	Rupture Disks	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
38517	Rupture Disks	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
38518	Rupture Disks	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37905	Rupture Disks	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
37921	Strainer (Element)	Filter	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-26	3.3.1-055	A
37908	Tanks (Inner N2 Storage Tank)	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
37919	Tanks (Outer N2 Storage Tank)	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37916	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37924	Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-26	3.3.1-055	A
37912	Valve Body	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
37977	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.A-439	3.3.1-193	B
37976	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
37938	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37939	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37940	Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37941	Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B

Table 3.3.2-4 Containment Systems Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38519	Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
38520	Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37906	Valve Body	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
37917	Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37979	Valve Body	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-26	3.3.1-055	A
37913	Valve Body	Structural Integrity (Attached)	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
38491	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
38492	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37942	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3.1-004	B
37943	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3.1-006	B
37907	Valve Body	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-4 Containment Systems Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33884	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33885	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
35057	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
35058	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
36578	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34511	Bolting (Ducting Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F1.A-794	3.3.1-260	A
34506	Bolting (Ducting Closure)	Mechanical Closure	Galvanized Bolting	Air - Indoor, Controlled (External)	None	None	V.F.EP-14	3.2.1-059	C
33886	Bolting (Ducting Closure)	Mechanical Closure	Galvanized Bolting	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
36583	Ducting and Components	Pressure Boundary	Aluminum Alloy	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F1.A-451a	3.3.1-189	D
33889	Ducting and Components	Pressure Boundary	Aluminum Alloy	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-763a	3.3.1-234	D
36584	Ducting and Components	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.F1.A-451a	3.3.1-189	D
33890	Ducting and Components	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-763a	3.3.1-234	D
34548	Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34550	Ducting and Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-08	3.3.1-090	A
34608	Ducting and Components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
35059	Ducting and Components	Pressure Boundary	Galvanized Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34609	Ducting and Components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-08	3.3.1-090	A
34364	Ducting and Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.F1.A-781a	3.3.1-094a	B
34365	Ducting and Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.AP-99a	3.3.1-094	B
34366	Ducting and Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.F1.A-781a	3.3.1-094a	B
36585	Ducting and Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.AP-99a	3.3.1-094	B
35811	Ducting and Components: Insulated	Pressure Boundary	Galvanized Steel	Air - Indoor, Controlled (Internal)	None	None	V.F.EP-14	3.2.1-059	A
35812	Ducting and Components: Insulated	Pressure Boundary	Galvanized Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	C
34507	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
34508	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
34509	Flexible Connection	Pressure Boundary	Elastomers	Condensation (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-504	3.3.1-085	A
34510	Flexible Connection	Pressure Boundary	Elastomers	Condensation (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			H, 1
39072	Heat Exchanger – (Admin Bldg. Supply) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
35181	Heat Exchanger – (Admin Bldg. Supply) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3.1-046	A
35182	Heat Exchanger – (Admin Bldg. Supply) Tube Side Components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F1.A-417	3.3.1-096b	A

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36589	Heat Exchanger – (Admin Bldg. Supply) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-205	3.3.1-050	A
36590	Heat Exchanger – (Admin Bldg. Supply) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-419	3.3.1-096a	A
36591	Heat Exchanger – (Admin Bldg. Supply) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
36608	Heat Exchanger – (Admin Bldg. Supply) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
34119	Heat Exchanger – (Chiller Condenser) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
34120	Heat Exchanger – (Chiller Condenser) Shell Side Components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	C
39073	Heat Exchanger – (Chiller Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
34094	Heat Exchanger – (Chiller Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3.1-046	A
34093	Heat Exchanger – (Chiller Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Gas (External)	None	None	VII.J.AP-6	3.3.1-121	C
33945	Heat Exchanger – (Chiller Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39074	Heat Exchanger – (Chiller Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
34088	Heat Exchanger – (Chiller Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3.1-046	A
35185	Heat Exchanger – (Chiller Condenser) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-205	3.3.1-050	A
35064	Heat Exchanger – (Chiller Condenser) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	C
35186	Heat Exchanger – (Chiller Condenser) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
35187	Heat Exchanger – (Chiller Condenser) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	C

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34124	Heat Exchanger – (Chiller Evaporator) Shell Side Components: Insulated	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	C
34125	Heat Exchanger – (Chiller Evaporator) Shell Side Components: Insulated	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	C
39075	Heat Exchanger – (Chiller Evaporator) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
34104	Heat Exchanger – (Chiller Evaporator) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3.1-046	A
34106	Heat Exchanger – (Chiller Evaporator) Tube Sheet	Pressure Boundary	Carbon Steel	Gas (External)	None	None	VII.J.AP-6	3.3.1-121	C
39130	Heat Exchanger – (Chiller Evaporator) Tube Side Components: Insulated	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3.1-046	A
34109	Heat Exchanger – (Chiller Evaporator) Tube Side Components: Insulated	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	C
35194	Heat Exchanger – (Chiller Evaporator) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-205	3.3.1-050	A
35195	Heat Exchanger – (Chiller Evaporator) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	C
34117	Heat Exchanger – (Chiller Evaporator) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
34113	Heat Exchanger – (Chiller Evaporator) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	C
35196	Heat Exchanger – (Cooling Coil #11 & #12) Shell Side Components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
35197	Heat Exchanger – (Cooling Coil #11 & #12) Shell Side Components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-08	3.3.1-090	C
39079	Heat Exchanger – (Cooling Coil #11 & #12) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
35199	Heat Exchanger – (Cooling Coil #11 & #12) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3.1-046	A
35200	Heat Exchanger – (Cooling Coil #11 & #12) Tube Side Components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F1.A-417	3.3.1-096b	A

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35201	Heat Exchanger – (Cooling Coil #11 & #12) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-205	3.3.1-050	A
35813	Heat Exchanger – (Cooling Coil #11 & #12) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-419	3.3.1-096a	A
35202	Heat Exchanger – (Cooling Coil #11 & #12) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
35203	Heat Exchanger – (Cooling Coil #11 & #12) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
39080	Heat Exchanger – (Lab Air Supply Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
35204	Heat Exchanger – (Lab Air Supply Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3.1-046	A
35205	Heat Exchanger – (Lab Air Supply Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F1.A-417	3.3.1-096b	A
33938	Heat Exchanger – (Lab Air Supply Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
33939	Heat Exchanger – (Lab Air Supply Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
39081	Piping, piping components, Insulated	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
35218	Piping, piping components, Insulated	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-202	3.3.1-045	A
35814	Piping, piping components, Insulated	Leakage Boundary (Spatial)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
37482	Piping, piping components, Insulated	Leakage Boundary (Spatial)	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
37485	Piping, piping components, Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
37589	Piping, piping components, Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B
39082	Piping, piping components, Insulated	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34161	Piping, piping components, Insulated	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-202	3.3.1-045	A
34158	Piping, piping components, Insulated	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
37481	Piping, piping components, Insulated	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
37486	Piping, piping components, Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
37590	Piping, piping components, Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B
35212	Pump Casing (Chilled Water Circ Pump): Insulated	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
35210	Pump Casing (Chilled Water Circ Pump): Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
36292	Pump Casing (Chilled Water Circ Pump): Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B
36515	Strainer (Element)	Filter	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
35215	Tanks (Chilled Water Expansion Tank)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39083	Tanks (Chilled Water Expansion Tank)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
35213	Tanks (Chilled Water Expansion Tank)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-202	3.3.1-045	A
35214	Tanks (Chilled Water Expansion Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-26	3.3.1-055	A
35216	Tanks (Chilled Water Side Stream Demineralizer)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39084	Tanks (Chilled Water Side Stream Demineralizer)	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
35217	Tanks (Chilled Water Side Stream Demineralizer)	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-202	3.3.1-045	A

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36236	Valve Body, Insulated	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-199	3.3.1-046	A
36234	Valve Body, Insulated	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
37483	Valve Body, Insulated	Leakage Boundary (Spatial)	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
37487	Valve Body, Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
37591	Valve Body, Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B
39085	Valve Body, Insulated	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
36239	Valve Body, Insulated	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-202	3.3.1-045	A
36238	Valve Body, Insulated	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
36243	Valve Body, Insulated	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-199	3.3.1-046	A
36244	Valve Body, Insulated	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.F1.AP-43	3.3.1-072	B
36242	Valve Body, Insulated	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 3
36241	Valve Body, Insulated	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-405a	3.3.1-132	E, 4
36564	Valve Body, Insulated	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
36246	Valve Body, Insulated	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-199	3.3.1-046	A
36245	Valve Body, Insulated	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
37484	Valve Body, Insulated	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37488	Valve Body, Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
37592	Valve Body, Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. This component/material/environment combination includes the aging effect of loss of material. This aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program.
2. The Control Room HVAC System chilled water environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and Long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
3. The control room chilled water closed loop cooling water system environment is a pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.

Table 3.3.2-5 Control Room HVAC System Summary of Aging Management Evaluation

4. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-6 Cranes, Hoists, and Refueling Equipment System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33318	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
33319	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
33320	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3.1-199	A
33327	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
33328	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
33329	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.TP-261	3.5.1-088	E, 1
33349	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Treated Water (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	V.E.E-418	3.2.1-076	E, 1
33350	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Treated Water (External)	Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.TP-261	3.5.1-088	E, 1

Table 3.3.2-6 Cranes, Hoists, and Refueling Equipment System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34136	Crane/Hoist (Fuel Prep Machine)	Structural Support	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	III.B5.T-37a	3.5.1-100	E, 1
33347	Crane/Hoist (Fuel Prep Machine)	Structural Support	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	III.B5.T-37a	3.5.1-100	I, 3
33348	Crane/Hoist (Fuel Prep Machine)	Structural Support	Aluminum Alloy	Treated Water (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.A4.AP-130	3.3.1-025	E, 1
43348	Crane/Hoist (Fuel Prep Machine)	Structural Support	Aluminum Alloy	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-130	3.3.1-025	D
34137	Crane/Hoist (Refueling Platform)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
33321	Crane/Hoist (Refueling Platform)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
33322	Crane/Hoist (Refueling Platform)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
33323	Crane/Hoist: rails, bridges, structural members, structural components	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A
33324	Crane/Hoist: rails, bridges, structural members, structural components	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Cumulative Fatigue Damage	TLAA	VII.B.A-06	3.3.1-001	A, 2
33325	Crane/Hoist: rails, bridges, structural members, structural components	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Deformation	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A

Table 3.3.2-6 Cranes, Hoists, and Refueling Equipment System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33326	Crane/Hoist: rails, bridges, structural members, structural components	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3.1-052	A

Table 3.3.2-6 Cranes, Hoists, and Refueling Equipment System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The Inspection of Overhead Heavy Load and Light Load (Related to Fuel Handling) Systems (B.2.1.13) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.
2. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.7.
3. The fuel prep machine is constructed of 6061-T6x aluminum alloy which is not susceptible to cracking (Reference: NUREG-2192 paragraph 3.3.2.2.8).

Table 3.3.2-7 Electric Steam Boiler System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38352	Boiler Casing (Electric Boiler 11)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38354	Boiler Casing (Electric Boiler 11)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38353	Boiler Casing (Electric Boiler 11)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
38346	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
38347	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38355	Flexible Connection	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38356	Flexible Connection	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38357	Flexible Connection	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
38358	Flexible Connection	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
38495	Heat Exchanger – (Condensate Cooler) Covers	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38361	Heat Exchanger – (Condensate Cooler) Nozzles	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	D
38362	Heat Exchanger – (Condensate Cooler) Nozzles	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	D
38963	Heat Exchanger – (Condensate Cooler) Nozzles	Leakage Boundary (Spatial)	Stainless Steel	Raw Water > 140°F (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)			G, 1
38365	Heat Exchanger – (Condensate Cooler) Nozzles	Leakage Boundary (Spatial)	Stainless Steel	Raw Water > 140°F (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
38359	Heat Exchanger – (Condensate Cooler) Nozzles	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
38360	Heat Exchanger – (Condensate Cooler) Nozzles	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
38366	Heat Exchanger – (Condensate Cooler) Plates	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	D

Table 3.3.2-7 Electric Steam Boiler System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38367	Heat Exchanger – (Condensate Cooler) Plates	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	D
38368	Heat Exchanger – (Condensate Cooler) Plates	Leakage Boundary (Spatial)	Stainless Steel	Raw Water > 140°F (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)			G, 1
38369	Heat Exchanger – (Condensate Cooler) Plates	Leakage Boundary (Spatial)	Stainless Steel	Raw Water > 140°F (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
38370	Heat Exchanger – (Condensate Cooler) Plates	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
38371	Heat Exchanger – (Condensate Cooler) Plates	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
38443	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
38444	Piping elements	Leakage Boundary (Spatial)	Glass	Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
38374	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39038	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 2
38376	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38375	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
38372	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38373	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
38466	Piping, piping components	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
38467	Piping, piping components	Leakage Boundary (Spatial)	Elastomers	Treated Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.A4.AP-101	3.3.1-085	A
38377	Tanks (Volume Chamber)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-7 Electric Steam Boiler System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38379	Tanks (Volume Chamber)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38378	Tanks (Volume Chamber)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
38468	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38470	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38469	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
38380	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38381	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B

Table 3.3.2-7 Electric Steam Boiler System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. Stainless steel in an environment of raw water > 140 F includes the aging effect of cracking. This aging effect is managed by the Open-Cycle Cooling Water System (B.2.1.11) program.
2. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33894	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33895	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36688	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
36689	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
35253	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
35254	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
33897	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-241	3.3.1-109	B
33898	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Underground (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36892	Compressor Housing (Starting Air)	Structural Integrity (Attached)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36893	Compressor Housing (Starting Air)	Structural Integrity (Attached)	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
34271	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B
34272	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
34269	Expansion Joints	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B
34270	Expansion Joints	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
34277	Expansion Joints	Pressure Boundary	Stainless Steel	Diesel Exhaust (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-128	3.3.1-083	A

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34278	Expansion Joints	Pressure Boundary	Stainless Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3.1-088	A
38964	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B
38965	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
38966	Flow Device	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-138	3.3.1-100	A
38710	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B
38711	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
38712	Flow Device	Throttle	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-138	3.3.1-100	A
33902	Heat Exchanger – (Lube Oil Coolers) Fins	Heat Transfer	Aluminum Alloy	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-154	3.3.1-101	C
33920	Heat Exchanger – (Lube Oil Coolers) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
33984	Heat Exchanger – (Lube Oil Coolers) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-131	3.3.1-098	A
34258	Heat Exchanger – (Lube Oil Coolers) Tube Sheet	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3.1-044	A
34259	Heat Exchanger – (Lube Oil Coolers) Tube Sheet	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
34282	Heat Exchanger – (Lube Oil Coolers) Tube Sheet	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-138	3.3.1-100	C
35298	Heat Exchanger – (Lube Oil Coolers) Tube Side Components	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3.1-044	A
35299	Heat Exchanger – (Lube Oil Coolers) Tube Side Components	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
35297	Heat Exchanger – (Lube Oil Coolers) Tube Side Components	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-138	3.3.1-100	C

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34262	Heat Exchanger – (Lube Oil Coolers) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water > 140°F (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-205	3.3.1-050	A
34283	Heat Exchanger – (Lube Oil Coolers) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	VII.H2.A-791	3.3.1-257	A
38749	Heat Exchanger – (Lube Oil Coolers) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water > 140°F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	A
34266	Heat Exchanger – (Lube Oil Coolers) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water > 140°F (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
34265	Heat Exchanger – (Lube Oil Coolers) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water > 140°F (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.H2.AP-43	3.3.1-072	D
34285	Heat Exchanger – (Lube Oil Coolers) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-133	3.3.1-099	C
33921	Heat Exchanger – (Raw Water Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
33936	Heat Exchanger – (Raw Water Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
36576	Heat Exchanger – (Raw Water Cooling) Tube Sheet	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3.1-044	A
36577	Heat Exchanger – (Raw Water Cooling) Tube Sheet	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
34288	Heat Exchanger – (Raw Water Cooling) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water > 140°F (External)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)			G, 2
35311	Heat Exchanger – (Raw Water Cooling) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water > 140°F (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	C
34289	Heat Exchanger – (Raw Water Cooling) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water > 140°F (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	C
35302	Heat Exchanger – (Raw Water Cooling) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
35310	Heat Exchanger – (Raw Water Cooling) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
35661	Heat Exchanger – (Raw Water Cooling) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35304	Heat Exchanger – (Raw Water Cooling) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
34264	Heat Exchanger – (Raw Water Cooling) Tubes	Heat Transfer	Stainless Steel	Closed Cycle Cooling Water > 140°F (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-188	3.3.1-050	A
34290	Heat Exchanger – (Raw Water Cooling) Tubes	Heat Transfer	Stainless Steel	Raw Water > 140°F (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-187	3.3.1-042	A
34267	Heat Exchanger – (Raw Water Cooling) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (External)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3.1-044	A
34268	Heat Exchanger – (Raw Water Cooling) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
34294	Heat Exchanger – (Raw Water Cooling) Tubes	Pressure Boundary	Stainless Steel	Raw Water > 140°F (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)			G, 2
38741	Heat Exchanger – (Raw Water Cooling) Tubes	Pressure Boundary	Stainless Steel	Raw Water > 140°F (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	C
34292	Heat Exchanger – (Raw Water Cooling) Tubes	Pressure Boundary	Stainless Steel	Raw Water > 140°F (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	C
35341	Heat Exchanger – (Turbo After Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
35340	Heat Exchanger – (Turbo After Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	C
33903	Heat Exchanger – (Turbo Aftercooler) Fins	Heat Transfer	Aluminum Alloy	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-419	3.3.1-096a	C
33937	Heat Exchanger – (Turbo Aftercooler) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
35659	Heat Exchanger – (Turbo Aftercooler) Tube Side Components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	C
34201	Heat Exchanger – (Turbo Aftercooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	A

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34209	Heat Exchanger – (Turbo Aftercooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Condensation (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-565	3.3.1-161	A
34200	Heat Exchanger – (Turbo Aftercooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3.1-046	A
34208	Heat Exchanger – (Turbo Aftercooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
34040	Hoses	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 3
34048	Hoses	Pressure Boundary	Copper Alloy with 15% Zinc or More	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-132	3.3.1-069	B
34175	Hoses	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-133	3.3.1-099	A
34192	Hoses	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
34194	Hoses	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	A
34248	Hoses	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B
34249	Hoses	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
34279	Hoses	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-138	3.3.1-100	A
33929	Muffler	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33962	Muffler	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3.1-088	A
34220	Piping elements	Pressure Boundary	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
34225	Piping elements	Pressure Boundary	Glass	Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
34226	Piping elements	Pressure Boundary	Glass	Fuel Oil (Internal)	None	None	VII.J.AP-49	3.3.1-117	A

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34227	Piping elements	Pressure Boundary	Glass	Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
33906	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34307	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B
33985	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
33900	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.A-451a	3.3.1-189	B
33899	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-763a	3.3.1-234	B
33901	Piping, piping components	Pressure Boundary	Aluminum Alloy	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-162	3.3.1-099	A
33907	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33928	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33931	Piping, piping components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	A
33955	Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
34047	Piping, piping components	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 1
33963	Piping, piping components	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3.1-088	A
33966	Piping, piping components	Pressure Boundary	Carbon Steel	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-070	B
33965	Piping, piping components	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-070	B

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33975	Piping, piping components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-127	3.3.1-097	A
34312	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
34308	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B
33986	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
33990	Piping, piping components	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3.1-109	B
33995	Piping, piping components	Pressure Boundary	Carbon Steel	Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-284	3.3.1-109	B
34006	Piping, piping components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38728	Piping, piping components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	A
38729	Piping, piping components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
34022	Piping, piping components	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
38714	Piping, piping components	Pressure Boundary	Cast Iron	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-070	B
35386	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
34030	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B
34029	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
34031	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.H2.A-51	3.3.1-072	B

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36627	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38715	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-133	3.3.1-099	A
38726	Piping, piping components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
38725	Piping, piping components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
34250	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B
34251	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
34295	Piping, piping components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-138	3.3.1-100	A
35258	Piping, piping components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	A
35257	Piping, piping components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	A
34502	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34505	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
33908	Pump Casing (Circ Lube Oil)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33977	Pump Casing (Circ Lube Oil)	Pressure Boundary	Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-127	3.3.1-097	A
34007	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35270	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35265	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B
35264	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
35266	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.H2.A-51	3.3.1-072	B
35268	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
34033	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B
34032	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
34034	Pump Casing (Cooling Water Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.H2.A-51	3.3.1-072	B
33910	Pump Casing (Fuel Oil Transfer)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33967	Pump Casing (Fuel Oil Transfer)	Pressure Boundary	Cast Iron	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-070	B
33912	Pump Casing (Motor Driven Fuel Oil)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33968	Pump Casing (Motor Driven Fuel Oil)	Pressure Boundary	Cast Iron	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-070	B
33916	Pump Casing (Turbo Lube Oil)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33982	Pump Casing (Turbo Lube Oil)	Pressure Boundary	Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-127	3.3.1-097	A
33917	Silencer	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33956	Silencer	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
35357	Strainer (Element)	Filter	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-127	3.3.1-097	A
34375	Strainer (Element)	Filter	Galvanized Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
34245	Strainer (Element)	Filter	Nickel Alloy	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H2.A-801	3.3.1-071	B
34273	Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B
34274	Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
35660	Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	A
34286	Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	A
33923	Tanks (Air Tank)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33957	Tanks (Air Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
33925	Tanks (Expansion Tank)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33934	Tanks (Expansion Tank)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	A
33958	Tanks (Expansion Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33926	Tanks (Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33960	Tanks (Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
33971	Tanks (Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-070	B
33959	Tanks (Fuel Oil Storage)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
33972	Tanks (Fuel Oil Storage)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-070	B
33989	Tanks (Fuel Oil Storage)	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3.1-109	B
33927	Tanks (Immersion Heater)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33935	Tanks (Immersion Heater)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	A
34376	Tanks (Intake Filter Oil Reservoir)	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34377	Tanks (Intake Filter Oil Reservoir)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
34378	Tanks (Intake Filter Oil Reservoir)	Pressure Boundary	Carbon Steel	Lubricating Oil (Waste Oil) (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-116	3.3.1-250	D
33918	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34309	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33988	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
33919	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33983	Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-127	3.3.1-097	A
34008	Valve Body	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34009	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-045	A
34020	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
34021	Valve Body	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
38751	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
34036	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-532	3.3.1-193	B
34035	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-194	3.3.1-037	A
34037	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.H2.A-51	3.3.1-072	B
36671	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 3
38750	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3.1-160	A
36672	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	A
38740	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.H2.AP-43	3.3.1-072	B

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36673	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
36678	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-133	3.3.1-099	A
38968	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
38743	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-193	3.3.1-034	A
36674	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-193	3.3.1-034	A
36676	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.H2.A-47	3.3.1-072	B
34193	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
34195	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3.1-046	A
34210	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
34211	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
34212	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-132	3.3.1-069	B
34213	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-132	3.3.1-069	B
34216	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-133	3.3.1-099	A
38752	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-193	3.3.1-034	A
34181	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-193	3.3.1-034	A
34217	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-174	3.3.1-108	B
34252	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3.1-004	B

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34253	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3.1-006	B
34254	Valve Body	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-186	3.3.1-043	A
34255	Valve Body	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water > 140°F (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
34297	Valve Body	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-138	3.3.1-100	A
35362	Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	A
34287	Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-040	A
35282	Valve Body	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
35286	Valve Body	Structural Integrity (Attached)	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-8 Emergency Diesel Generator System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. This component is associated with carbon steel EDG engine exhaust piping in a diesel exhaust environment. TLAA is used to manage the aging effect(s) applicable to this component type, material and environment combination. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.
2. Stainless steel in an environment of raw water > 140 F includes the aging effect of cracking. This aging effect is managed by the Open-Cycle Cooling Water System (B.2.1.11) program.
3. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34638	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
34647	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34644	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
34648	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34646	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
34650	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34645	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-241	3.3.1-109	B
34649	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36750	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
36328	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
36329	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36876	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
36382	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
36881	Expansion Joints	Pressure Boundary	Stainless Steel	Diesel Exhaust (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-128	3.3.1-083	A
36383	Expansion Joints	Pressure Boundary	Stainless Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3.1-088	A
35173	Fire Barriers (Concrete Curbs)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Cracking	Fire Protection (B.2.1.15)	VII.G.A-90	3.3.1-060	A

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
45173	Fire Barriers (Concrete Curbs)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Cracking	Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3.1-060	B
35174	Fire Barriers (Concrete Curbs)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-90	3.3.1-060	A
45174	Fire Barriers (Concrete Curbs)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Loss of Material	Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3.1-060	B
35175	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Indoor, Uncontrolled (External)	Cracking	Fire Protection (B.2.1.15)	VII.G.A-90	3.3.1-060	A
45175	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Indoor, Uncontrolled (External)	Cracking	Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3.1-060	B
35176	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-90	3.3.1-060	A
45176	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Indoor, Uncontrolled (External)	Loss of Material	Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3.1-060	B
35177	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Cracking	Fire Protection (B.2.1.15)	VII.G.A-90	3.3.1-060	A
45177	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Cracking	Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3.1-060	B
35178	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-90	3.3.1-060	A
45178	Fire Barriers (Concrete Walls, Ceilings, Floors)	Fire Barrier	Reinforced Concrete	Air - Outdoor (External)	Loss of Material	Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3.1-060	B
35179	Fire Barriers (Doors)	Fire Barrier	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	C
36748	Fire Barriers (Doors)	Fire Barrier	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	Fire Protection (B.2.1.15)	VII.G.A-21	3.3.1-059	A
35180	Fire Barriers (Doors)	Fire Barrier	Carbon Steel	Air - Outdoor (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	C
36749	Fire Barriers (Doors)	Fire Barrier	Carbon Steel	Air - Outdoor (External)	Loss of Material Due to Wear	Fire Protection (B.2.1.15)	VII.G.A-21	3.3.1-059	A
35457	Fire Barriers (Electrical Raceway)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Change in Material Properties	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A
35458	Fire Barriers (Electrical Raceway)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Cracking/Delamination	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A
35459	Fire Barriers (Electrical Raceway)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36751	Fire Barriers (Electrical Raceway)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Separation	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A
36388	Fire Barriers (For Steel Components)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Change in Material Properties	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
36389	Fire Barriers (For Steel Components)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Cracking/Delamination	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
36390	Fire Barriers (For Steel Components)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
36391	Fire Barriers (For Steel Components)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Separation	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
35192	Fire Barriers (Masonry Walls)	Fire Barrier	Concrete Block	Air - Indoor, Uncontrolled (External)	Cracking	Fire Protection (B.2.1.15)	VII.G.A-626	3.3.1-179	A
45192	Fire Barriers (Masonry Walls)	Fire Barrier	Concrete Block	Air - Indoor, Uncontrolled (External)	Cracking	Masonry Walls (B.2.1.32)	VII.G.A-626	3.3.1-179	B
35193	Fire Barriers (Masonry Walls)	Fire Barrier	Concrete Block	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-626	3.3.1-179	A
45193	Fire Barriers (Masonry Walls)	Fire Barrier	Concrete Block	Air - Indoor, Uncontrolled (External)	Loss of Material	Masonry Walls (B.2.1.32)	VII.G.A-626	3.3.1-179	B
35449	Fire Barriers (Penetration Seals)	Fire Barrier	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	C
36394	Fire Barriers (Penetration Seals)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Change in Material Properties	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
36395	Fire Barriers (Penetration Seals)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Cracking/Delamination	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
36396	Fire Barriers (Penetration Seals)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
36393	Fire Barriers (Penetration Seals)	Fire Barrier	Cementitious Fireproofing	Air - Indoor, Uncontrolled (External)	Separation	Fire Protection (B.2.1.15)	VII.G.A-806	3.3.1-268	A
35450	Fire Barriers (Penetration Seals)	Fire Barrier	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening, Loss of Strength, Shrinkage	Fire Protection (B.2.1.15)	VII.G.A-19	3.3.1-057	A
36402	Fire Barriers (Penetration Seals)	Fire Barrier	Galvanized Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-789	3.3.1-255	C
36752	Fire Barriers (Penetration Seals)	Fire Barrier	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	Fire Protection (B.2.1.15)	VII.I.A-797a	3.3.1-263	E, 1

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36403	Fire Barriers (Penetration Seals)	Fire Barrier	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	Fire Protection (B.2.1.15)	VII.I.A-797a	3.3.1-263	E, 1
36404	Fire Barriers (Penetration Seals)	Fire Barrier	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	Fire Protection (B.2.1.15)	VII.I.A-797a	3.3.1-263	E, 1
35451	Fire Barriers (Penetration Seals)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Change in Material Properties	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A
35452	Fire Barriers (Penetration Seals)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Cracking/Delamination	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A
35453	Fire Barriers (Penetration Seals)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A
36401	Fire Barriers (Penetration Seals)	Fire Barrier	Silicate Fireproofing	Air - Indoor, Uncontrolled (External)	Separation	Fire Protection (B.2.1.15)	VII.G.A-807	3.3.1-269	A
34926	Fire Barriers: Damper Housings	Fire Barrier	Galvanized Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-789	3.3.1-255	A
34927	Fire Barriers: Damper Housings	Fire Barrier	Galvanized Steel	Condensation (Internal)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-789	3.3.1-255	A
36754	Fire Barriers: Damper Housings	Fire Barrier	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	Fire Protection (B.2.1.15)	VII.G.A-789	3.3.1-255	A
36405	Fire Barriers: Damper Housings	Fire Barrier	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-789	3.3.1-255	A
36407	Fire Barriers: Damper Housings	Fire Barrier	Stainless Steel	Condensation (Internal)	Cracking	Fire Protection (B.2.1.15)	VII.G.A-789	3.3.1-255	A
36406	Fire Barriers: Damper Housings	Fire Barrier	Stainless Steel	Condensation (Internal)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.A-789	3.3.1-255	A
34928	Fire Hydrant	Pressure Boundary	Cast Iron	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.AP-149	3.3.1-063	B
34929	Fire Hydrant	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.AP-149	3.3.1-063	B
34930	Fire Hydrant	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
34935	Fire Hydrant	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.AP-149	3.3.1-063	B
34932	Fire Hydrant	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34933	Fire Hydrant	Pressure Boundary	Cast Iron	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3.1-109	B
34934	Fire Hydrant	Pressure Boundary	Cast Iron	Soil (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-02	3.3.1-072	D
35382	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
37578	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
36517	Flexible Connection	Pressure Boundary	Elastomers	Condensation (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-504	3.3.1-085	A
35444	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
35445	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
35446	Flow Device	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
35447	Flow Device	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
36612	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
36613	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
35442	Flow Device	Throttle	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
35443	Flow Device	Throttle	Stainless Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
35477	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 9

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38975	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-473b	3.3.1-160	E, 8
35479	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
35478	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
35480	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-47	3.3.1-072	D
35472	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	VII.G.A-791	3.3.1-257	A
35473	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-187	3.3.1-042	A
35476	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.G.AP-133	3.3.1-099	C
35475	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
35474	Heat Exchanger – (Motor Driven Fire Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
34936	Hose Stations	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36524	Hoses	Pressure Boundary	Elastomers	Fuel Oil (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H1.A-660	3.3.1-085	A

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36523	Hoses	Pressure Boundary	Elastomers	Gas (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-729	3.3.1-085	A
36518	Hoses	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
36519	Hoses	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
36520	Hoses	Pressure Boundary	Stainless Steel	Underground (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-714a	3.3.1-146	B
36521	Hoses	Pressure Boundary	Stainless Steel	Underground (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-775a	3.3.1-246	B
36566	Piping elements	Pressure Boundary	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
36567	Piping elements	Pressure Boundary	Glass	Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
35397	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.G.A-649	3.3.1-197	A
35401	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
35399	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-650	3.3.1-198	A
35361	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
35206	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
45206	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	A
55206	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
35234	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
45234	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-722	3.3.1-157	B
39053	Piping, piping components	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 7
35380	Piping, piping components	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3.1-088	A
36469	Piping, piping components	Pressure Boundary	Carbon Steel	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-234	3.3.1-070	B
35235	Piping, piping components	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-234	3.3.1-070	B
35381	Piping, piping components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
35237	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
35239	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
35236	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36759	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Open-Cycle Cooling Water System (B.2.1.11)	VII.C3.A-400a	3.3.1-127	A
35241	Piping, piping components	Pressure Boundary	Carbon Steel	Underground (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-284	3.3.1-109	B
35465	Piping, piping components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
35466	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
35467	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
35468	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
35469	Piping, piping components	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36568	Piping, piping components	Pressure Boundary	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36569	Piping, piping components	Pressure Boundary	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-416	3.3.1-138	B
36570	Piping, piping components	Pressure Boundary	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-414	3.3.1-139	B
36571	Piping, piping components	Pressure Boundary	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Material/Selective Leaching	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-415	3.3.1-140	B
36572	Piping, piping components	Pressure Boundary	Cast Iron (with Internal Coatings)	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3.1-109	B
36573	Piping, piping components	Pressure Boundary	Cast Iron (with Internal Coatings)	Soil (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-02	3.3.1-072	B
35363	Piping, piping components	Pressure Boundary	Concrete	Raw Water (Internal)	Cracking	Fire Water System (B.2.1.16)	VII.G.A-647	3.3.1-195	B
35364	Piping, piping components	Pressure Boundary	Concrete	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-647	3.3.1-195	B
35365	Piping, piping components	Pressure Boundary	Concrete	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-647	3.3.1-195	B
35366	Piping, piping components	Pressure Boundary	Concrete	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-157	3.3.1-103	B
35367	Piping, piping components	Pressure Boundary	Concrete	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-157	3.3.1-103	B
35368	Piping, piping components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36471	Piping, piping components	Pressure Boundary	Galvanized Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35369	Piping, piping components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	A
35370	Piping, piping components	Pressure Boundary	Galvanized Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
36766	Piping, piping components	Pressure Boundary	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
36762	Piping, piping components	Pressure Boundary	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
36765	Piping, piping components	Pressure Boundary	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
36820	Piping, piping components	Pressure Boundary	Polymer	Fuel Oil (External)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 2
36767	Piping, piping components	Pressure Boundary	Polymer	Fuel Oil (External)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 2
36819	Piping, piping components	Pressure Boundary	Polymer	Fuel Oil (External)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 2
36822	Piping, piping components	Pressure Boundary	Polymer	Fuel Oil (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 2
36768	Piping, piping components	Pressure Boundary	Polymer	Fuel Oil (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 2
36821	Piping, piping components	Pressure Boundary	Polymer	Fuel Oil (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			G, 2

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36771	Piping, piping components	Pressure Boundary	Polymer	Soil (External)	Cracking or Blistering	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.A-797a	3.3.1-263	E, 3
36769	Piping, piping components	Pressure Boundary	Polymer	Soil (External)	Hardening or Loss of Strength Due to Polymeric Degradation	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.A-797a	3.3.1-263	E, 3
36770	Piping, piping components	Pressure Boundary	Polymer	Soil (External)	Loss of Material Due to Peeling, Delamination, Wear	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.A-797a	3.3.1-263	E, 3
36774	Piping, piping components	Pressure Boundary	Polymer	Underground (External)	Cracking or Blistering	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.A-797a	3.3.1-263	E, 3
36772	Piping, piping components	Pressure Boundary	Polymer	Underground (External)	Hardening or Loss of Strength Due to Polymeric Degradation	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.A-797a	3.3.1-263	E, 3
36773	Piping, piping components	Pressure Boundary	Polymer	Underground (External)	Loss of Material Due to Peeling, Delamination, Wear	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.A-797a	3.3.1-263	E, 3
35489	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
35490	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
35491	Piping, piping components	Pressure Boundary	Stainless Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-136	3.3.1-071	B
34889	Pump Casing (Abandoned Construction Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.G.A-649	3.3.1-197	A
34890	Pump Casing (Abandoned Construction Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
34888	Pump Casing (Abandoned Construction Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-650	3.3.1-198	A
38951	Pump Casing (Abandoned Construction Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34943	Pump Casing (Abandoned Pressure Maintenance Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.G.A-649	3.3.1-197	A
34944	Pump Casing (Abandoned Pressure Maintenance Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
34945	Pump Casing (Abandoned Pressure Maintenance Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-650	3.3.1-198	A
38952	Pump Casing (Abandoned Pressure Maintenance Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
34891	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
34896	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
34902	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
34895	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
34894	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
34900	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36555	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
36559	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
36560	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36561	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
36556	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36558	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36557	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36562	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
34903	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
34904	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
34905	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
34906	Pump Casing (Diesel Driven Fire Pump)	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
34685	Pump Casing (Diesel Fuel Oil Transfer Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
34684	Pump Casing (Diesel Fuel Oil Transfer Pumps)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-234	3.3.1-070	B
35481	Pump Casing (Fire Header Press. Maintenance Pumps)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
35482	Pump Casing (Fire Header Press. Maintenance Pumps)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
35484	Pump Casing (Fire Header Press. Maintenance Pumps)	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-650	3.3.1-198	A
34937	Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
34938	Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
34939	Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
34942	Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
34940	Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34941	Pump Casing (Motor Driven Fire Pump)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
35485	Pump Casing (U2 Construction Fire Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.G.A-649	3.3.1-197	A
35486	Pump Casing (U2 Construction Fire Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
35487	Pump Casing (U2 Construction Fire Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-650	3.3.1-198	A
35488	Pump Casing (U2 Construction Fire Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
38953	Silencer / Muffler	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35385	Silencer / Muffler	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3.1-088	A
36775	Spray Nozzles	Spray	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.A-451a	3.3.1-189	B
36540	Spray Nozzles	Spray	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-763a	3.3.1-234	B
36776	Spray Nozzles	Spray	Aluminum Alloy	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.A-451a	3.3.1-189	B
36542	Spray Nozzles	Spray	Aluminum Alloy	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.H2.A-763a	3.3.1-234	B
36545	Spray Nozzles	Spray	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	A
36544	Spray Nozzles	Spray	Carbon Steel	Condensation (Internal)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	A
36535	Spray Nozzles	Spray	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 9
36537	Spray Nozzles	Spray	Copper Alloy with 15% Zinc or More	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 9

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36777	Spray Nozzles	Spray	Copper Alloy with 15% Zinc or More	Condensation (Internal)	Loss of Material	Fire Protection (B.2.1.15)	V.D2.EP-113b	3.2.1-006	E, 1
36512	Spray Nozzles	Spray	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
36513	Spray Nozzles	Spray	Copper Alloy with less than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	D
36514	Spray Nozzles	Spray	Copper Alloy with less than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	D
34952	Spray Nozzles	Spray	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
34953	Spray Nozzles	Spray	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
34954	Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
34955	Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
34911	Sprinklers	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
34910	Sprinklers	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B
34909	Sprinklers	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B
34907	Sprinklers	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B
34908	Sprinklers	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B
34912	Sprinklers	Spray	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
34916	Sprinklers	Spray	Copper Alloy with less than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B
34915	Sprinklers	Spray	Copper Alloy with less than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B
34913	Sprinklers	Spray	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B
34914	Sprinklers	Spray	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36525	Strainer (Element)	Filter	Nickel Alloy	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H2.A-801	3.3.1-071	B
36526	Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3.1-004	B
36527	Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3.1-006	B
35470	Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
35471	Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-55	3.3.1-066	B
34833	Tanks (Air Receivers for Diesel Start)	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B
34831	Tanks (Air Receivers for Diesel Start)	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
34882	Tanks (CO2 Storage Unit)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	A
34883	Tanks (CO2 Storage Unit)	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
36546	Tanks (Day Tank)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36547	Tanks (Day Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3.1-055	A
34854	Tanks (Day Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-234	3.3.1-070	B
36779	Tanks (Diesel Storage Tank)	Pressure Boundary	Fiberglass	Condensation (Internal)	Cracking, Blistering, Loss of Material	Fuel Oil Chemistry (B.2.1.18)			G, 4
34879	Tanks (Diesel Storage Tank)	Pressure Boundary	Fiberglass	Fuel Oil (Internal)	Cracking, Blistering, Loss of Material	Fuel Oil Chemistry (B.2.1.18)			G, 5
34874	Tanks (Diesel Storage Tank)	Pressure Boundary	Fiberglass	Soil (External)	Cracking, Blistering, Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-176	3.3.1-104	B
34876	Tanks (Diesel Storage Tank)	Pressure Boundary	Fiberglass	Soil (External)	Loss of Material Due to Peeling, Delamination, Wear	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.A-462	3.3.1-177	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35372	Tanks (Diesel Storage Tank)	Pressure Boundary	Fiberglass	Underground (External)	Cracking, Blistering, Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)			G, 6
34881	Tanks (Halon)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	A
34880	Tanks (Halon)	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
36498	Tanks (Retard Chambers)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
36499	Tanks (Retard Chambers)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36500	Tanks (Retard Chambers)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
36502	Tanks (Retard Chambers)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36501	Tanks (Retard Chambers)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
35409	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.G.A-649	3.3.1-197	A
35411	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
35410	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-650	3.3.1-198	A
35426	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
45426	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-058	A
55426	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-412	3.3.1-136	D
35425	Valve Body	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
45425	Valve Body	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-722	3.3.1-157	B
35421	Valve Body	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
35428	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
35429	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
35427	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
35464	Valve Body	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3.1-109	B
36550	Valve Body	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36551	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36552	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3.1-193	B
36553	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-064	B
36554	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3.1-072	B
36614	Valve Body	Pressure Boundary	Cast Iron	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3.1-109	B
36615	Valve Body	Pressure Boundary	Cast Iron	Soil (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.G.A-02	3.3.1-072	B
36487	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 9
36488	Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or More	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
35462	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3.1-235	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35461	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
36486	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-132	3.3.1-069	B
35463	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-132	3.3.1-069	B
36548	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.1.16)	VII.G.AP-197	3.3.1-064	B
36549	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.16)	VII.G.AP-197	3.3.1-064	B

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The Fire Protection (B.2.1.15) program will be used to manage the aging effect(s) applicable to this component type, material, and environment combination.
2. The aging effects of fiberglass reinforced plastic pipe in a fuel oil environment are assumed to include hardening and loss of strength, loss of material, and cracking or blistering due to the presence of water and contaminants. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage the aging effect(s) applicable to this material and environment combination.
3. The Buried and Underground Piping and Tanks (B.2.1.27) program will be used to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-9 Fire Detection and Protection System Summary of Aging Management Evaluation

4. The aging effects of fiberglass in the fuel oil tank airspace (condensation environment) are assumed to include cracking, blistering, and loss of material due to the presence of moisture. The Fuel Oil Chemistry (B.2.1.18) program will be used to manage the aging effect(s) applicable to this component, material and environment combination since this program includes periodic inspection of tank internal surfaces.
5. The aging effects of fiberglass in fuel oil are assumed to include cracking, blistering, and loss of material due to the presence of water. The Fuel Oil Chemistry (B.2.1.18) program will be used to manage the aging effect(s) applicable to this component, material and environment combination since this program includes periodic inspection of tank internal surfaces and periodic sampling for the presence of water.
6. The aging effects of fiberglass in the tank vault airspace (underground environment) are assumed to include cracking, blistering, and loss of material due to the presence of moisture. The Buried and Underground Piping and Tanks (B.2.1.27) program will be used to manage the aging effect(s) applicable to this component, material and environment combination since this program performs periodic inspection of the external surfaces of components located in underground environments.
7. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.
8. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage the aging effect applicable to this component type, material, and environment combination.
9. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-10 Liquid Poison System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33220	Accumulator (Liquid Poison)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33858	Accumulator (Liquid Poison)	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
33165	Accumulator (Liquid Poison)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33166	Accumulator (Liquid Poison)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33167	Accumulator (Liquid Poison)	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
33118	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33119	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
33221	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
33114	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33115	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
33122	Electric Heaters	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	D
33123	Electric Heaters	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	D
33121	Electric Heaters	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	D
33170	Gearbox	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33171	Gearbox	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-127	3.3.1-097	C

Table 3.3.2-10 Liquid Poison System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33124	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33130	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E2.A-439	3.3.1-193	B
33129	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
33447	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
33446	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
33131	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33116	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33172	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
33132	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33133	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33112	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33134	Piping, piping components	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
33135	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33136	Pump Casing (Liquid Poison Pump)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33117	Pump Casing (Liquid Poison Pump)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33137	Pump Casing (Liquid Poison Pump)	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
33164	Strainer (Element)	Filter	Stainless Steel	Sodium Pentaborate Solution (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B

Table 3.3.2-10 Liquid Poison System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33138	Tanks (Liquid Poison Tank)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33139	Tanks (Liquid Poison Tank)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33141	Tanks (Liquid Poison Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33142	Tanks (Liquid Poison Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33140	Tanks (Liquid Poison Tank)	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
33143	Tanks (Pulse Dampener)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33144	Tanks (Pulse Dampener)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33168	Tanks (Pulse Dampener)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33145	Tanks (Test Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33146	Tanks (Test Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33147	Tanks (Test Tank)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33148	Tanks (Test Tank)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33169	Tanks (Test Tank)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33151	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33449	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
33448	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-10 Liquid Poison System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33157	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33158	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33159	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33160	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33161	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33162	Valve Body	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E2.AP-141	3.3.1-203	B
33163	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-10 Liquid Poison System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

None.

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37517	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
37516	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
37520	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
37518	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
37519	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
37524	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
37527	Piping elements	Leakage Boundary (Spatial)	Glass	Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
37863	Piping elements	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37861	Piping elements	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37862	Piping elements	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
37864	Piping elements	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
37866	Piping elements	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
37865	Piping elements	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38384	Piping elements	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
38386	Piping elements	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
38385	Piping elements	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
37528	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	VII.E5.A-763a	3.3.1-234	I, 1
38976	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	VII.E5.A-451a	3.3.1-189	I, 1
37529	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-130	3.3.1-025	B
37568	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37656	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37532	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
37655	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37531	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37569	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37611	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
37576	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37617	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.F1.A-416	3.3.1-138	B
37610	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.F1.A-414	3.3.1-139	B
37618	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Waste Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E5.A-416	3.3.1-138	B
37607	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Waste Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E5.A-414	3.3.1-139	B
37570	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37657	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37620	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37619	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
37571	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37623	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
37622	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37621	Piping, piping components	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Material/Selective Leaching	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-415	3.3.1-140	B
37631	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
37630	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
37627	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	B
37625	Piping, piping components	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37632	Piping, piping components	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	None	None	VII.J.AP-269	3.3.1-119	A
37638	Piping, piping components	Leakage Boundary (Spatial)	PVC	Waste Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-787d	3.3.1-253	A
37573	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37572	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
37639	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
37641	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
37640	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A
37563	Pump Casing (Makeup Demin. Regen. Waste Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37659	Pump Casing (Makeup Demin. Regen. Waste Pump)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37559	Pump Casing (Makeup Demin. Regen. Waste Pump)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37560	Pump Casing (Makeup Demin. Regen. Waste Pump)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E5.A-547	3.3.1-072	B
37566	Pump Casing (Temporary Reactor Water Cleanup Fill and Pressure Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
37565	Pump Casing (Temporary Reactor Water Cleanup Fill and Pressure Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
37564	Pump Casing (Temporary Reactor Water Cleanup Fill and Pressure Pump)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
37642	Tanks (Anion Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37643	Tanks (Anion Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37580	Tanks (Anion Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37567	Tanks (Anion Deoxygenation Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37645	Tanks (Anion Deoxygenation Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
37644	Tanks (Anion Deoxygenation Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37648	Tanks (Cation Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37647	Tanks (Cation Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
37646	Tanks (Cation Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37649	Tanks (Filter)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37652	Tanks (Filter)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37651	Tanks (Filter)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37669	Tanks (Flush Water Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37874	Tanks (Flush Water Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-401	3.2.1-072	E, 4
37873	Tanks (Flush Water Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-414	3.2.1-073	E, 4
37667	Tanks (Flush Water Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-416	3.3.1-138	E, 4
37668	Tanks (Flush Water Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-414	3.3.1-139	E, 4
37709	Tanks (Makeup Demineralized Water Storage Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	VII.E5.A-763a	3.3.1-234	I, 2
38977	Tanks (Makeup Demineralized Water Storage Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	VII.E5.A-451a	3.3.1-189	I, 2
38978	Tanks (Makeup Demineralized Water Storage Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Condensation (Internal)	None	None	VII.E5.A-451a	3.3.1-189	I, 2
37875	Tanks (Makeup Demineralized Water Storage Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Condensation (Internal)	none	None	VII.E5.A-763a	3.3.1-234	I, 2
37687	Tanks (Makeup Demineralized Water Storage Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-130	3.3.1-025	B
37711	Tanks (Makeup Demineralizer Regeneration Waste Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37872	Tanks (Makeup Demineralizer Regeneration Waste Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-401	3.2.1-072	B

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37871	Tanks (Makeup Demineralizer Regeneration Waste Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-414	3.2.1-073	B
37819	Tanks (Makeup Demineralizer Regeneration Waste Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Waste Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E5.A-416	3.3.1-138	B
37713	Tanks (Makeup Demineralizer Regeneration Waste Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Waste Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E5.A-414	3.3.1-139	B
37718	Tanks (Mixed Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37716	Tanks (Mixed Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
37717	Tanks (Mixed Bed)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37719	Tanks (Purifier)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37721	Tanks (Purifier)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37722	Tanks (Purifier)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37723	Tanks (Sodium Sulphite Tank)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37876	Tanks (Sodium Sulphite Tank)	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-26	3.3.1-055	A
37725	Tanks (Sodium Sulphite Tank)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37724	Tanks (Sodium Sulphite Tank)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
37730	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37732	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
37733	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
37734	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37735	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37736	Valve Body	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37739	Valve Body	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
37738	Valve Body	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37740	Valve Body	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Waste Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E5.A-416	3.3.1-138	B
37742	Valve Body	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Waste Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E5.A-414	3.3.1-139	B
38722	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38721	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
38720	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
38719	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
37756	Valve Body	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37806	Valve Body	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37808	Valve Body	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
37807	Valve Body	Leakage Boundary (Spatial)	Cast Iron (with Internal Coatings)	Raw Water (Internal)	Loss of Material/Selective Leaching	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-415	3.3.1-140	B
37788	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 3
37789	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	B
37791	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E4.AP-32	3.3.1-072	B
37766	Valve Body	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
37767	Valve Body	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	None	None	VII.J.AP-269	3.3.1-119	A
37768	Valve Body	Leakage Boundary (Spatial)	PVC	Waste Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-787d	3.3.1-253	A
37800	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
37799	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
37798	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
37797	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37795	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. Components are constructed of a 3xxx series aluminum alloy which is not susceptible to stress corrosion cracking (NUREG-2192 Section 3.3.2.2.8). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, these components are not susceptible to loss of material due to pitting and crevice corrosion (NUREG-2192 Section 3.3.2.2.10).
2. Components are constructed of 5052-H34 aluminum alloy, which contains less than 3.5 weight percent of magnesium, and is not susceptible to stress corrosion cracking (NUREG-2192 Section 3.3.2.2.8). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, loss of material due to pitting and crevice corrosion need not be managed (NUREG-2192 Section 3.3.2.2.10).

Table 3.3.2-11 Makeup Demineralizer System Summary of Aging Management Evaluation

3. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.
4. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination. The internally coated flush water tank meets the six criteria in GALL-SLR AMP XI.M42, Element 4, to use the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program in lieu of the Internal Coatings/Linings for In-Scope Piping, Piping Component, Heat Exchangers, and Tanks (B.2.1.28) program.

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35494	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
35495	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
35505	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
35506	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
35507	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Waste Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-728	3.3.1-085	A
37118	Expansion Joints	Leakage Boundary (Spatial)	Elastomers	Waste Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-550	3.3.1-096	A
35541	Heat Exchanger – (Cleanup Filter Sludge Tank Blower Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
37159	Heat Exchanger – (Cleanup Filter Sludge Tank Blower Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
35548	Heat Exchanger – (Cleanup Filter Sludge Tank Blower Aftercooler) Shell Side Components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
39089	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
37867	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
37868	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Sheet	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-778	3.3.1-249	C

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35525	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39090	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
35515	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
35529	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
38066	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	V.D2.EP-37	3.2.1-034	I, 1
38146	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	none	None	VII.C2.A-473a	3.3.1-160	I, 3
38846	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
38147	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Waste Water (External)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-473c	3.3.1-160	A
38177	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Waste Water (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-272	3.3.1-095	A
35539	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Waste Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-272	3.3.1-095	A
38069	Heat Exchanger – (Drywell Equipment Drain Tank #11 & #12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Waste Water (External)	None	None	VII.E5.A-547	3.3.1-072	I, 1
37982	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Sheet	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
38072	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Sheet	Pressure Boundary	Stainless Steel	Waste Water (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-275	3.3.1-095	A

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37983	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Sheet	Pressure Boundary	Stainless Steel	Waste Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-275	3.3.1-095	A
37986	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Side Components	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
38073	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Side Components	Pressure Boundary	Stainless Steel	Waste Water (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-275	3.3.1-095	A
37985	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tube Side Components	Pressure Boundary	Stainless Steel	Waste Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-275	3.3.1-095	A
37987	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
38074	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tubes	Pressure Boundary	Stainless Steel	Waste Water (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-275	3.3.1-095	A
37988	Heat Exchanger – (Reactor Bldg. Equipment Drain Tank) Tubes	Pressure Boundary	Stainless Steel	Waste Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-275	3.3.1-095	A
37093	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
37094	Piping elements	Leakage Boundary (Spatial)	Glass	Waste Water (Internal)	None	None	VII.J.AP-277	3.3.1-119	A
35550	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39046	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 4
38078	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38075	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37168	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
35552	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37095	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
38148	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37096	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
35562	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38149	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
37880	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
35558	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A
35559	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38151	Piping, piping components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38150	Piping, piping components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
35560	Piping, piping components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35598	Pump Casing (Condensate Iron Prefilter BWRT Transfer Pump 11 & 12)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37173	Pump Casing (Condensate Iron Prefilter BWRT Transfer Pump 11 & 12)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
35596	Pump Casing (Condensate Iron Prefilter BWRT Transfer Pump 11 & 12)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37283	Pump Casing (Condensate Iron Prefilter BWRT Transfer Pump 11 & 12)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E5.A-547	3.3.1-072	B
35597	Pump Casing (Fuel Pool Filter Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37175	Pump Casing (Fuel Pool Filter Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
35595	Pump Casing (Fuel Pool Filter Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37284	Pump Casing (Fuel Pool Filter Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E5.A-547	3.3.1-072	B
35564	Tanks (Backwash Receiving Tank Primary and Overflow)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
38152	Tanks (Backwash Receiving Tank Primary and Overflow)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
38153	Tanks (Backwash Receiving Tank Primary and Overflow)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
35565	Tanks (Backwash Receiving Tank Primary and Overflow)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
37127	Tanks (Backwash Receiving Tank Primary and Overflow)	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37126	Tanks (Fuel Pool Filter Sludge Tank)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37134	Tanks (Fuel Pool Filter Sludge Tank)	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-26	3.3.1-055	A
38154	Tanks (Fuel Pool Filter Sludge Tank)	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37130	Tanks (Fuel Pool Filter Sludge Tank)	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38076	Tanks (Scram Discharge Volume Holding Tank)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37133	Tanks (Scram Discharge Volume Holding Tank)	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-26	3.3.1-055	A
38156	Tanks (Scram Discharge Volume Holding Tank)	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37129	Tanks (Scram Discharge Volume Holding Tank)	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37472	Tanks (Waste Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
37137	Tanks (Waste Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
38157	Tanks (Waste Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
37135	Tanks (Waste Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-751b	3.3.1-222	B
37131	Tanks (Waste Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35569	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38159	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38079	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
38161	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
35571	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
35599	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
37392	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37321	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37322	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Waste Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E5.A-547	3.3.1-072	B
37138	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
37139	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-272	3.3.1-095	A
37193	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35573	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38077	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35575	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A
35579	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38163	Valve Body	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38162	Valve Body	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
35580	Valve Body	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37194	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35581	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38164	Valve Body	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A
35582	Valve Body	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-12 Radioactive Waste System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. Drywell Equipment Drain Tank #11 & #12 heat exchanger tubes are fabricated from admiralty brass (inhibited brass) and therefore per NUREG-2191 Table IX.C are not susceptible to selective leaching.
2. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
3. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.
4. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-13 Reactor Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35819	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
35816	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36952	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36953	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36954	Flow Device	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
36955	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36956	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36957	Flow Device	Throttle	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
35863	Heat Exchanger – (RBCW Heat Exchangers) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39091	Heat Exchanger – (RBCW Heat Exchangers) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
35864	Heat Exchanger – (RBCW Heat Exchangers) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
35894	Heat Exchanger – (RBCW Heat Exchangers) Tube Sheet	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
35892	Heat Exchanger – (RBCW Heat Exchangers) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
35893	Heat Exchanger – (RBCW Heat Exchangers) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
36643	Heat Exchanger – (RBCW Heat Exchangers) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
35973	Heat Exchanger – (RBCW Heat Exchangers) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
35976	Heat Exchanger – (RBCW Heat Exchangers) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B

Table 3.3.2-13 Reactor Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35977	Heat Exchanger – (RBCW Heat Exchangers) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
35987	Heat Exchanger – (RBCW Heat Exchangers) Tubes	Heat Transfer	Stainless Steel	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-188	3.3.1-050	A
35986	Heat Exchanger – (RBCW Heat Exchangers) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
35988	Heat Exchanger – (RBCW Heat Exchangers) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
35989	Heat Exchanger – (RBCW Heat Exchangers) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
35990	Heat Exchanger – (RBCW Heat Exchangers) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	C
35992	Piping elements	Structural Integrity (Attached)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
35991	Piping elements	Structural Integrity (Attached)	Glass	Gas (Internal)	None	None	VII.J.AP-98	3.3.1-117	A
36001	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39092	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36000	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36972	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36973	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36975	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
36004	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39093	Piping, piping components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36003	Piping, piping components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-13 Reactor Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36961	Piping, piping components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39094	Piping, piping components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36964	Piping, piping components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36965	Piping, piping components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
36150	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 3
36148	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A
36149	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-43	3.3.1-072	B
36147	Piping, piping components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 2
36986	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
36988	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A
36966	Piping, piping components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
39095	Piping, piping components	Pressure Boundary	Galvanized Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36969	Piping, piping components	Pressure Boundary	Galvanized Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36008	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36009	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36010	Piping, piping components	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-13 Reactor Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37107	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39096	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
37109	Piping, piping components	Structural Integrity (Attached)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36958	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36959	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36960	Piping, piping components	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
36151	Pump Casing (Reactor Building Cooling Water Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39097	Pump Casing (Reactor Building Cooling Water Pumps)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36153	Pump Casing (Reactor Building Cooling Water Pumps)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36154	Strainer (Element)	Filter	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
36155	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39098	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36157	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36164	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
36165	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A
36161	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-13 Reactor Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39099	Valve Body	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36163	Valve Body	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36168	Valve Body	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39100	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36167	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36169	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
36170	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
36171	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A
36172	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36173	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36174	Valve Body	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
37099	Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39101	Valve Body	Structural Integrity (Attached)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
37101	Valve Body	Structural Integrity (Attached)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36990	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36991	Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B

Table 3.3.2-13 Reactor Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36992	Valve Body	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-13 Reactor Building Closed Loop Cooling System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
2. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.
3. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-14 Reactor Building HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33351	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33352	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34513	Bolting (Ducting Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F2.A-794	3.3.1-260	A
33362	Bolting (Ducting Closure)	Mechanical Closure	Galvanized Bolting	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
33480	Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33481	Ducting and Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-08	3.3.1-090	A
33363	Ducting and Components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
33364	Ducting and Components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-08	3.3.1-090	A
33964	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
33970	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
33973	Flexible Connection	Pressure Boundary	Elastomers	Condensation (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-504	3.3.1-085	A
33974	Flexible Connection	Pressure Boundary	Elastomers	Condensation (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			H, 1

Table 3.3.2-14 Reactor Building HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33388	Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F2.A-417	3.3.1-096b	A
34299	Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
33387	Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
33390	Heat Exchanger – (Area Coolers) Tubes	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
33389	Heat Exchanger – (Area Coolers) Tubes	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
33429	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33430	Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-26	3.3.1-055	A
33878	Piping, piping components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33879	Piping, piping components	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-26	3.3.1-055	A
33882	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
33883	Piping, piping components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
33431	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33432	Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-26	3.3.1-055	A
34613	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-14 Reactor Building HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34614	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34516	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
33433	Valve Body	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33434	Valve Body	Pressure Boundary	Cast Iron	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-26	3.3.1-055	A

Table 3.3.2-14 Reactor Building HVAC System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. This component/material/environment combination includes the aging effect of loss of material. This aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program.

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33188	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33189	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34138	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
33185	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33186	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
33825	Heat Exchanger – (Auxiliary Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39102	Heat Exchanger – (Auxiliary Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
33826	Heat Exchanger – (Auxiliary Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-189	3.3.1-046	A
33828	Heat Exchanger – (Auxiliary Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	D
34049	Heat Exchanger – (Auxiliary Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-131	3.3.1-098	A
33815	Heat Exchanger – (Auxiliary Cleanup Pump Oil Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
34411	Heat Exchanger – (Auxiliary Cleanup Pump Oil Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-131	3.3.1-098	A
34413	Heat Exchanger – (Auxiliary Cleanup Pump Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
34412	Heat Exchanger – (Auxiliary Cleanup Pump Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-133	3.3.1-099	C
33816	Heat Exchanger – (Auxiliary Cleanup Pump Pedestal Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39103	Heat Exchanger – (Auxiliary Cleanup Pump Pedestal Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
33817	Heat Exchanger – (Auxiliary Cleanup Pump Pedestal Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-189	3.3.1-046	A
33760	Heat Exchanger – (Cleanup Filter Precoat Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39104	Heat Exchanger – (Cleanup Filter Precoat Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
33761	Heat Exchanger – (Cleanup Filter Precoat Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-189	3.3.1-046	A
33769	Heat Exchanger – (Cleanup Filter Precoat Cooler) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
34050	Heat Exchanger – (Cleanup Filter Precoat Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
34414	Heat Exchanger – (Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39105	Heat Exchanger – (Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
34415	Heat Exchanger – (Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-189	3.3.1-046	A
34416	Heat Exchanger – (Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	D
34417	Heat Exchanger – (Cleanup Pump Bearing Cooler) Shell Side Components	Pressure Boundary	Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.H2.AP-131	3.3.1-098	A
34421	Heat Exchanger – (Cleanup Pump Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 5
34423	Heat Exchanger – (Cleanup Pump Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-133	3.3.1-099	C
34428	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34440	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-43	3.3.1-072	D
38979	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 3
34427	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-133	3.3.1-099	C
34433	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39106	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
34436	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-189	3.3.1-046	A
34437	Heat Exchanger – (Cleanup Pump Oil Cooler) Tube Side Components	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	D
34429	Heat Exchanger – (Cleanup Pump Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
34430	Heat Exchanger – (Cleanup Pump Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-133	3.3.1-099	C
33771	Heat Exchanger – (Non Regenerative) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39107	Heat Exchanger – (Non Regenerative) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
33772	Heat Exchanger – (Non Regenerative) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-189	3.3.1-046	A
33773	Heat Exchanger – (Non Regenerative) Tube Sheet	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
33774	Heat Exchanger – (Non Regenerative) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
33775	Heat Exchanger – (Non Regenerative) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
33776	Heat Exchanger – (Non Regenerative) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33777	Heat Exchanger – (Non Regenerative) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	D
33778	Heat Exchanger – (Non Regenerative) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	D
33779	Heat Exchanger – (Non Regenerative) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
33780	Heat Exchanger – (Non Regenerative) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
33781	Heat Exchanger – (Non Regenerative) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
33782	Heat Exchanger – (Non Regenerative) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-019	B
33783	Heat Exchanger – (Non Regenerative) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
33784	Heat Exchanger – (Regenerative) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	D
33785	Heat Exchanger – (Regenerative) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	D
33786	Heat Exchanger – (Regenerative) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-019	B
33787	Heat Exchanger – (Regenerative) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
33788	Heat Exchanger – (Regenerative) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
33789	Heat Exchanger – (Regenerative) Tube Side Components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	D
33790	Heat Exchanger – (Regenerative) Tube Side Components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	D
33791	Heat Exchanger – (Regenerative) Tube Side Components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-120	3.3.1-019	B
33792	Heat Exchanger – (Regenerative) Tube Side Components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
33523	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33524	Piping elements	Leakage Boundary (Spatial)	Glass	Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
33525	Piping elements	Leakage Boundary (Spatial)	Glass	Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
34140	Piping elements	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
33829	Piping elements	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
34139	Piping elements	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
34141	Piping elements	Leakage Boundary (Spatial)	Polymer	Treated Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
33830	Piping elements	Leakage Boundary (Spatial)	Polymer	Treated Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
34142	Piping elements	Leakage Boundary (Spatial)	Polymer	Treated Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3.1-263	A
33526	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33527	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-127	3.3.1-097	A
33528	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-34	3.3.1-002	A, 1
33530	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
33529	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
33531	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-16	3.4.1-005	B

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33532	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 5
34154	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
34155	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-32	3.3.1-072	B
33536	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33537	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33538	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
34051	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
34156	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
34052	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33539	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34159	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
34055	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
33542	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
33541	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
34095	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
34096	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
34097	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
39127	Piping, piping components greater than or equal to 4 NPS	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39128	Piping, piping components greater than or equal to 4 NPS	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
39032	Piping, piping components greater than or equal to 4 NPS	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 200°F (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.1.5)	VII.E4.A-61	3.3.1-110	A
49032	Piping, piping components greater than or equal to 4 NPS	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 200°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-61	3.3.1-110	B
39049	Piping, piping components greater than or equal to 4 NPS	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 200°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 1
39033	Piping, piping components greater than or equal to 4 NPS	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 200°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33545	Pump Casing (Auxiliary Cleanup Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33546	Pump Casing (Auxiliary Cleanup Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33547	Pump Casing (Auxiliary Cleanup Pump)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
33548	Pump Casing (Auxiliary Cleanup Pump)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33543	Pump Casing (Cleanup Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33544	Pump Casing (Cleanup Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33549	Pump Casing (Cleanup Pump)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33551	Pump Casing (Filter Aid Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33555	Pump Casing (Filter Aid Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
33553	Pump Casing (Filter Aid Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
33554	Pump Casing (Filter Aid Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3.1-072	B

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33556	Pump Casing (Precoat Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33559	Pump Casing (Precoat Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
33557	Pump Casing (Precoat Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
33558	Pump Casing (Precoat Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3.1-072	B
33560	Pump Casing (Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33562	Pump Casing (Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
33561	Pump Casing (Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
33853	Pump Casing (Sludge Pump)	Leakage Boundary (Spatial)	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3.1-072	B
33563	Tanks (Cleanup Demineralizer)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33564	Tanks (Cleanup Demineralizer)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33565	Tanks (Cleanup Demineralizer)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33573	Tanks (Cleanup Pump Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33579	Tanks (Cleanup Pump Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-401	3.2.1-072	E, 6
33580	Tanks (Cleanup Pump Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-414	3.2.1-073	E, 6

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33574	Tanks (Cleanup Pump Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Lubricating Oil (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-416	3.3.1-138	E, 6
33575	Tanks (Cleanup Pump Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Lubricating Oil (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-414	3.3.1-139	E, 6
33593	Tanks (Cleanup Pump Pac Loc Reservoir)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33594	Tanks (Cleanup Pump Pac Loc Reservoir)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33595	Tanks (Cleanup Pump Pac Loc Reservoir)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33576	Tanks (Cleanup Pump Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33577	Tanks (Cleanup Pump Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
34058	Tanks (Cleanup Pump Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
33578	Tanks (Cleanup Pump Surge Tank)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33583	Tanks (Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33586	Tanks (Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-401	3.2.1-072	E, 6
33587	Tanks (Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-414	3.2.1-073	E, 6
33584	Tanks (Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E4.A-416	3.3.1-138	E, 6

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33585	Tanks (Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E4.A-414	3.3.1-139	E, 6
33588	Tanks (Filter Precoat Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33591	Tanks (Filter Precoat Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-401	3.2.1-072	E, 6
33592	Tanks (Filter Precoat Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-414	3.2.1-073	E, 6
33589	Tanks (Filter Precoat Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E4.A-416	3.3.1-138	E, 6
33590	Tanks (Filter Precoat Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E4.A-414	3.3.1-139	E, 6
33741	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33752	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
33751	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
33753	Valve Body	Leakage Boundary (Spatial)	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33754	Valve Body	Leakage Boundary (Spatial)	Cast Austenitic Stainless Steel (CASS)	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
34164	Valve Body	Leakage Boundary (Spatial)	Cast Austenitic Stainless Steel (CASS)	Treated Water > 482°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34059	Valve Body	Leakage Boundary (Spatial)	Cast Austenitic Stainless Steel (CASS)	Treated Water > 482°F (Internal)	Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	V.D2.E-11	3.2.1-010	E, 4
34166	Valve Body	Leakage Boundary (Spatial)	Cast Austenitic Stainless Steel (CASS)	Treated Water > 482°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33534	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
33535	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
33748	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33745	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33746	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
34053	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
34054	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
33755	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33757	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
33756	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
33758	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33759	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
34038	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.
2. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
3. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.
4. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-15 Reactor Water Cleanup Summary of Aging Management Evaluation

5. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.
6. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination. The internally coated cleanup pump oil reservoir tank, filter aid mix tank and filter precoat mix tank meet the six criteria in GALL-SLR AMP XI.M42, Element 4, to use the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program in lieu of the Internal Coatings/Linings for In-Scope Piping, Piping Component, Heat Exchangers, and Tanks (B.2.1.28) program.

Table 3.3.2-16 Sampling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38303	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
38304	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38396	Drip Pan	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38398	Drip Pan	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38397	Drip Pan	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38452	Heat Exchanger – (Noble Chem HWC Sample Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39108	Heat Exchanger – (Noble Chem HWC Sample Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
38453	Heat Exchanger – (Noble Chem HWC Sample Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-189	3.3.1-046	A
38454	Heat Exchanger – (Noble Chem HWC Sample Cooler) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-770a	3.3.1-241	B
38456	Heat Exchanger – (Noble Chem HWC Sample Cooler) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
38455	Heat Exchanger – (Noble Chem HWC Sample Cooler) Tube Side Components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
38449	Heat Exchanger – (Noble Chem HWC Sample Cooler) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3.1-047	A
38451	Heat Exchanger – (Noble Chem HWC Sample Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
38450	Heat Exchanger – (Noble Chem HWC Sample Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
38541	Heat Exchanger – (Sample Coolers) Shell Side Components	Leakage Boundary (Spatial)	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-770a	3.3.1-241	B
38542	Heat Exchanger – (Sample Coolers) Shell Side Components	Leakage Boundary (Spatial)	Nickel Alloy	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-471	3.3.1-147	C

Table 3.3.2-16 Sampling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38539	Heat Exchanger – (Sample Coolers) Shell Side Components	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.F1.A-770a	3.3.1-241	B
38540	Heat Exchanger – (Sample Coolers) Shell Side Components	Pressure Boundary	Nickel Alloy	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-471	3.3.1-147	C
38534	Heat Exchanger – (Sample Coolers) Tubes	Pressure Boundary	Nickel Alloy	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-471	3.3.1-147	C
38536	Heat Exchanger – (Sample Coolers) Tubes	Pressure Boundary	Nickel Alloy	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	D
38535	Heat Exchanger – (Sample Coolers) Tubes	Pressure Boundary	Nickel Alloy	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
38529	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
38530	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
38531	Hoses	Leakage Boundary (Spatial)	Elastomers	Raw Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.AP-75	3.3.1-085	A
38532	Hoses	Leakage Boundary (Spatial)	Elastomers	Raw Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.AP-76	3.3.1-096	A
38525	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
38526	Piping elements	Leakage Boundary (Spatial)	Glass	Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
38387	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38393	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
38391	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-16 Sampling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38395	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38556	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
38389	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38388	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
38734	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
38732	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
38733	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A
38737	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
38735	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
38736	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A
38308	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38309	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38423	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-16 Sampling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38330	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
38310	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
38329	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
39050	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	A, 2
38328	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
38305	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38306	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38307	Piping, piping components	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
38435	Pump Casing (Post Accident Sample Pumps)	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38523	Pump Casing (Post Accident Sample Pumps)	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-140	3.3.1-022	B
38561	Pump Casing (Tunnel Sample Pumps)	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E5.A-451a	3.3.1-189	B
38438	Pump Casing (Tunnel Sample Pumps)	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-763a	3.3.1-234	B
38562	Pump Casing (Tunnel Sample Pumps)	Leakage Boundary (Spatial)	Aluminum Alloy	Raw Water (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E5.A-451a	3.3.1-189	B
38441	Pump Casing (Tunnel Sample Pumps)	Leakage Boundary (Spatial)	Aluminum Alloy	Raw Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-776b	3.3.1-247	B
38957	Tanks (Sampling Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38958	Tanks (Sampling Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B

Table 3.3.2-16 Sampling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38432	Tanks (Sampling Tank)	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
38411	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
38412	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
38413	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
38415	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3.1-193	B
38563	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
38403	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38404	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38424	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
38408	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3.1-134	A
38405	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
38407	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
38406	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B
38400	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38401	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B

Table 3.3.2-16 Sampling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38402	Valve Body	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
38522	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
38521	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-110	3.3.1-203	B

Table 3.3.2-16 Sampling System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The reactor building and turbine building closed loop cooling water systems environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
2. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33455	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33451	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36277	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Condensation (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
36276	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Condensation (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
33454	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
33453	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33452	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
35070	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
35069	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34383	Bolting (Closure)	Mechanical Closure	Titanium Alloy Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
35504	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
35503	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
35510	Flow Device	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
35502	Flow Device	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
38987	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
38986	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
35583	Flow Device	Throttle	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
35149	Flow Device	Throttle	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35255	Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	VII.C1.A-791	3.3.1-257	A
35256	Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
35251	Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VII.C1.AP-133	3.3.1-099	C
38988	Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
35247	Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
35248	Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
35250	Heat Exchanger – (Service Water Pump Motor Cooler) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-66	3.3.1-072	B
35240	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
35591	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
35242	Hoses	Leakage Boundary (Spatial)	Elastomers	Raw Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.AP-75	3.3.1-085	A
35590	Hoses	Leakage Boundary (Spatial)	Elastomers	Raw Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.AP-76	3.3.1-096	A
35229	Hoses	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
35230	Hoses	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
35231	Hoses	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34491	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34492	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34493	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35662	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-400a	3.3.1-127	A
35153	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
35151	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
35152	Piping, piping components	Leakage Boundary (Spatial)	Galvanized Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35666	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A, 1
35667	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A, 1
37650	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A, 1
35668	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A, 1
35669	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A, 1
37653	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A, 1

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34488	Piping, piping components	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
34489	Piping, piping components	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
34145	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
34487	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
34486	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34490	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34482	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34480	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34481	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35671	Piping, piping components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-400a	3.3.1-127	A
34471	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
34472	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34473	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35674	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-400a	3.3.1-127	A
34474	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
34475	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34476	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34477	Piping, piping components: Insulated	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
34483	Piping, piping components: Insulated	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34478	Piping, piping components: Insulated	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34479	Piping, piping components: Insulated	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35675	Piping, piping components: Insulated	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-400a	3.3.1-127	A
34569	Piping, piping components: Insulated	Pressure Boundary	Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
34566	Piping, piping components: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34564	Piping, piping components: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34565	Piping, piping components: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
38989	Piping, piping components: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-400a	3.3.1-127	A
34567	Piping, piping components: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
35496	Pump Casing (Chlorine Monitor Sample Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35497	Pump Casing (Chlorine Monitor Sample Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
35499	Pump Casing (Chlorine Monitor Sample Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35498	Pump Casing (Chlorine Monitor Sample Pump)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34450	Pump Casing (Demineralizer Feed Pumps)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34451	Pump Casing (Demineralizer Feed Pumps)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34453	Pump Casing (Demineralizer Feed Pumps)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34452	Pump Casing (Demineralizer Feed Pumps)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34318	Pump Casing (Emergency Service Water Pumps)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
34319	Pump Casing (Emergency Service Water Pumps)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
35167	Pump Casing (Emergency Service Water Pumps)	Pressure Boundary	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34317	Pump Casing (Emergency Service Water Pumps)	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34316	Pump Casing (Emergency Service Water Pumps)	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
35188	Pump Casing (Filter Backwash)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35189	Pump Casing (Filter Backwash)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
35191	Pump Casing (Filter Backwash)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35190	Pump Casing (Filter Backwash)	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34305	Pump Casing (Service Water Discharge Radiation Monitor)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
34306	Pump Casing (Service Water Discharge Radiation Monitor)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34303	Pump Casing (Service Water Discharge Radiation Monitor)	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
35512	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35147	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
35146	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35148	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (External)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34602	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35144	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34601	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
35145	Pump Casing (Service Water Pumps)	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34391	Pump Casing (SW Dispersant)	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
35588	Pump Casing (SW Dispersant)	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
35207	Pump Casing (Trasar Panel Booster Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
35208	Pump Casing (Trasar Panel Booster Pump)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
35209	Pump Casing (Trasar Panel Booster Pump)	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
35587	Strainer (Element) (Emergency and Normal Service Water Pump Discharge Strainers)	Filter	Stainless Steel	Raw Water (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34239	Strainer (Element) (Emergency and Normal Service Water Pump Discharge Strainers)	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34395	Tanks (Clearwell)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34399	Tanks (Clearwell)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34401	Tanks (Clearwell)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34404	Tanks (Precipitator)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34402	Tanks (Precipitator)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34403	Tanks (Precipitator)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34233	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34234	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34236	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34444	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34441	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34443	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34442	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34231	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
34232	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35586	Valve Body	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A, 1
34206	Valve Body	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A, 1
37664	Valve Body	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3.1-263	A, 1
35585	Valve Body	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A, 1
34205	Valve Body	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A, 1
37665	Valve Body	Leakage Boundary (Spatial)	Polymer	Raw Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3.1-263	A, 1
34224	Valve Body	Leakage Boundary (Spatial)	PVC	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
34230	Valve Body	Leakage Boundary (Spatial)	PVC	Raw Water (Internal)	Loss of Material Due to Wear	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-787a	3.3.1-253	A
34222	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
34221	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
34223	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34198	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34237	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34189	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34191	Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34448	Valve Body	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
34449	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34445	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34447	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34446	Valve Body	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34197	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
34238	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
34188	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
34143	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3.1-004	B
34144	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3.1-006	B
34240	Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34187	Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34151	Valve Body: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
34148	Valve Body: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34150	Valve Body: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34466	Valve Body: Insulated	Leakage Boundary (Spatial)	Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
34468	Valve Body: Insulated	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34470	Valve Body: Insulated	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34469	Valve Body: Insulated	Leakage Boundary (Spatial)	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34169	Valve Body: Insulated	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
34168	Valve Body: Insulated	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
34171	Valve Body: Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
34172	Valve Body: Insulated	Leakage Boundary (Spatial)	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B
34170	Valve Body: Insulated	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34108	Valve Body: Insulated	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
34098	Valve Body: Insulated	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34100	Valve Body: Insulated	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
34111	Valve Body: Insulated	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34461	Valve Body: Insulated	Pressure Boundary	Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
34462	Valve Body: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34463	Valve Body: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34465	Valve Body: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
34464	Valve Body: Insulated	Pressure Boundary	Cast Iron	Raw Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	B
34084	Valve Body: Insulated	Pressure Boundary	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
34056	Valve Body: Insulated	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
34057	Valve Body: Insulated	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-034	A
34498	Valve Body: Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3.1-205	B
34499	Valve Body: Insulated	Pressure Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3.1-232	B
34501	Valve Body: Insulated	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A
34500	Valve Body: Insulated	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-17 Service Water System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. Piping and valves identified as Polymer are a Polyvinylidene Fluoride thermoplastic polymer resin (Kynar Solid).

Table 3.3.2-18 Shutdown Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33465	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33466	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
34011	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
34012	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38046	Flow Device	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
34016	Flow Device	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
34013	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
34014	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38047	Flow Device	Throttle	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
34017	Flow Device	Throttle	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33859	Heat Exchanger – (Shutdown Cooling Pump) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39109	Heat Exchanger – (Shutdown Cooling Pump) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
33861	Heat Exchanger – (Shutdown Cooling Pump) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E4.AP-189	3.3.1-046	A
38487	Heat Exchanger – (Shutdown Cooling Pump) Tube Side Components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
33864	Heat Exchanger – (Shutdown Cooling Pump) Tube Side Components	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	D
33862	Heat Exchanger – (Shutdown Cooling Pump) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
33863	Heat Exchanger – (Shutdown Cooling Pump) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-140	3.3.1-022	D

Table 3.3.2-18 Shutdown Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33866	Heat Exchanger – (Shutdown Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39110	Heat Exchanger – (Shutdown Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
33867	Heat Exchanger – (Shutdown Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E4.AP-189	3.3.1-046	A
39111	Heat Exchanger – (Shutdown Cooling) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Closed Cycle Cooling Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 2
33868	Heat Exchanger – (Shutdown Cooling) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E4.AP-189	3.3.1-046	A
33869	Heat Exchanger – (Shutdown Cooling) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B
33870	Heat Exchanger – (Shutdown Cooling) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
33872	Heat Exchanger – (Shutdown Cooling) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
36118	Heat Exchanger – (Shutdown Cooling) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
33874	Heat Exchanger – (Shutdown Cooling) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D
36119	Heat Exchanger – (Shutdown Cooling) Tubes	Heat Transfer	Stainless Steel	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.E4.AP-188	3.3.1-050	A
36121	Heat Exchanger – (Shutdown Cooling) Tubes	Heat Transfer	Stainless Steel	Treated Water > 140°F (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	VII.E3.AP-139	3.3.1-027	B
33877	Heat Exchanger – (Shutdown Cooling) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.E4.AP-191	3.3.1-047	A
33875	Heat Exchanger – (Shutdown Cooling) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3.1-020	B

Table 3.3.2-18 Shutdown Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33876	Heat Exchanger – (Shutdown Cooling) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-111	3.3.1-203	B
33495	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33499	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
33496	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
33500	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33501	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33502	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33503	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
33504	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
33505	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
36480	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36482	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
36481	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
33474	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33475	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33478	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33476	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
33506	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1

Table 3.3.2-18 Shutdown Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33477	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33507	Pump Casing (Shutdown Cooling Pump)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33508	Pump Casing (Shutdown Cooling Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
33479	Pump Casing (Shutdown Cooling Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
33509	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33510	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33946	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33511	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
33512	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
36483	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36485	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.A-532	3.3.1-193	B
36484	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
33469	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
33470	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
33471	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B
33472	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E4.A-773	3.3.1-244	B
33473	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-18 Shutdown Cooling System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Programs column indicates that cumulative fatigue damage due to fatigue for this component is evaluated in Section 4.3.
2. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34988	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
34989	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36755	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3.1-142	B
37473	Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38286	Fuel Storage Racks (Spent Fuel Storage Racks)	Absorb Neutrons	Boraflex	Treated Water (External)	None	None	VII.A2.A-87	3.3.1-051	I, 4
38287	Fuel Storage Racks (Spent Fuel Storage Racks)	Absorb Neutrons	Boral	Treated Water (External)	Reduction of Neutron Absorbing Capacity; Change in Dimensions and Loss of Material	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.1.26)	VII.A2.AP-236	3.3.1-102	A
38288	Fuel Storage Racks (Spent Fuel Storage Racks)	Structural Support	Stainless Steel	Treated Water (External)	Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-002	C, 3
38289	Fuel Storage Racks (Spent Fuel Storage Racks)	Structural Support	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A2.A-98	3.3.1-125	B
35436	Heat Exchanger – (Fuel Pool) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39112	Heat Exchanger – (Fuel Pool) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
35437	Heat Exchanger – (Fuel Pool) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.A4.AP-189	3.3.1-046	A
35438	Heat Exchanger – (Fuel Pool) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
35519	Heat Exchanger – (Fuel Pool) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-140	3.3.1-022	D
35520	Heat Exchanger – (Fuel Pool) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35522	Heat Exchanger – (Fuel Pool) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.A4.A-439	3.3.1-193	B
35521	Heat Exchanger – (Fuel Pool) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	D

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35527	Heat Exchanger – (Fuel Pool) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-205	3.3.1-050	A
35523	Heat Exchanger – (Fuel Pool) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)	VIII.E.SP-100	3.4.1-018	B
35528	Heat Exchanger – (Fuel Pool) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
38991	Heat Exchanger – (Fuel Pool) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.E4.AP-43	3.3.1-072	I, 6
48991	Heat Exchanger – (Fuel Pool) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.A-473a	3.3.1-160	I, 5
35524	Heat Exchanger – (Fuel Pool) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-140	3.3.1-022	D
35850	Heat Exchanger – (Fuel Pool) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Treated Water (Internal)	None	None	VII.F1.AP-65	3.3.1-072	I, 6
36756	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
36757	Piping elements	Leakage Boundary (Spatial)	Glass	Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
35532	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35534	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.A4.A-439	3.3.1-193	B
35533	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
35537	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35538	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
35540	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
35535	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35536	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
36758	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35043	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
35777	Pump Casing (Body Feed Pump)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35780	Pump Casing (Body Feed Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.A4.A-439	3.3.1-193	B
35778	Pump Casing (Body Feed Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
35781	Pump Casing (Body Feed Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.A4.AP-31	3.3.1-072	B
35854	Pump Casing (Circulating Pump)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36760	Pump Casing (Circulating Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.A4.A-439	3.3.1-193	B
35154	Pump Casing (Circulating Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E3.AP-106	3.3.1-021	B
36761	Pump Casing (Circulating Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.A4.AP-31	3.3.1-072	B
35555	Pump Casing (Precoat Pump)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35556	Pump Casing (Precoat Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.A4.A-439	3.3.1-193	B
35157	Pump Casing (Precoat Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
35557	Pump Casing (Precoat Pump)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.A4.AP-31	3.3.1-072	B
35972	Strainer (Element)	Filter	Elemental Carbon	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)			F, 2
36783	Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
35969	Tanks (Body Feed Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38340	Tanks (Body Feed Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-401	3.2.1-072	B
38341	Tanks (Body Feed Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-414	3.2.1-073	B
35970	Tanks (Body Feed Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E4.A-416	3.3.1-138	B
35971	Tanks (Body Feed Filter Aid Mix Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E4.A-414	3.3.1-139	B
36784	Tanks (Fuel Pool Filter)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36785	Tanks (Fuel Pool Filter)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E4.A-416	3.3.1-138	B
36786	Tanks (Fuel Pool Filter)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E4.A-414	3.3.1-139	B
35566	Tanks (Precoat Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38342	Tanks (Precoat Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-401	3.2.1-072	B
38343	Tanks (Precoat Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-414	3.2.1-073	B
35974	Tanks (Precoat Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E4.A-416	3.3.1-138	B
35975	Tanks (Precoat Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.E4.A-414	3.3.1-139	B
35576	Tanks (Surge Tank)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35577	Tanks (Surge Tank)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
38350	Tanks (Surge Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
38351	Tanks (Surge Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
35578	Tanks (Surge Tank)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
35542	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35543	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
35544	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
38124	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.A4.A-451a	3.3.1-189	B

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38125	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.A4.A-763a	3.3.1-234	B
38123	Valve Body	Pressure Boundary	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-130	3.3.1-025	B
35978	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
35980	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.A4.A-439	3.3.1-193	B
35979	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.E4.AP-106	3.3.1-021	B
38127	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
38126	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-140	3.3.1-022	B
35545	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.E4.AP-209a	3.3.1-004	B
35546	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.E4.AP-221a	3.3.1-006	B
36868	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B
35547	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-110	3.3.1-203	B

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
2. Material not in NUREG-2191 for this component. The Water Chemistry (B.2.1.2) Program will be used to manage this component type.
3. The TLAA designation in the Aging Management Programs column indicates fatigue of this component is evaluated in Section 4.7.
4. NMP1 Technical Specification Amendment 234 removed credit for the Boraflex neutron absorber material in the two remaining spent fuel racks that contain Boraflex, based on a 3 out of 4 fuel loading pattern with cell blockers reducing the Boraflex rack capacity from 414 to 306 fuel storage locations. Therefore, the reduction of neutron-absorbing capacity is not an applicable aging effect.

Table 3.3.2-19 Spent Fuel Pool Cooling and Storage System Summary of Aging Management Evaluation

5. The reactor building closed loop cooling water system environment is a pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.
6. Tubes are fabricated from SB111 admiralty brass (inhibited brass) and therefore per NUREG-2191 Table IX.C are not susceptible to selective leaching.

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36625	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
36626	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
36816	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36815	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36813	Flow Device	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
37424	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
37423	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36811	Flow Device	Throttle	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
36789	Heat Exchanger – (TBCW Heat Exchanger 11) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39115	Heat Exchanger – (TBCW Heat Exchanger 11) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36788	Heat Exchanger – (TBCW Heat Exchanger 11) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
39204	Heat Exchanger – (TBCW Heat Exchanger 11) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
39205	Heat Exchanger – (TBCW Heat Exchanger 11) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
39206	Heat Exchanger – (TBCW Heat Exchanger 11) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
37426	Heat Exchanger – (TBCW Heat Exchanger 11) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
36793	Heat Exchanger – (TBCW Heat Exchanger 11) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36794	Heat Exchanger – (TBCW Heat Exchanger 11) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-416	3.3.1-138	B
36795	Heat Exchanger – (TBCW Heat Exchanger 11) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coatings)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C1.A-414	3.3.1-139	B
39214	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	A
39213	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
39212	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
39211	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.AP-43	3.3.1-072	I, 3
49211	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.A-473a	3.3.1-160	I, 2
39210	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
39209	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
39208	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
39207	Heat Exchanger – (TBCW Heat Exchanger 11) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	None	None	VII.C1.A-47	3.3.1-072	I, 3
39203	Heat Exchanger – (TBCW Heat Exchanger 12) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.I.AP-41	3.3.1-080	A
39201	Heat Exchanger – (TBCW Heat Exchanger 12) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
39202	Heat Exchanger – (TBCW Heat Exchanger 12) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
37431	Heat Exchanger – (TBCW Heat Exchanger 12) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36791	Heat Exchanger – (TBCW Heat Exchanger 12) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
36792	Heat Exchanger – (TBCW Heat Exchanger 12) Tube Sheet	Pressure Boundary	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
39215	Heat Exchanger – (TBCW Heat Exchanger 12) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39216	Heat Exchanger – (TBCW Heat Exchanger 12) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
39217	Heat Exchanger – (TBCW Heat Exchanger 12) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
39218	Heat Exchanger – (TBCW Heat Exchanger 12) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
36680	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	A
36679	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
36666	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A
37480	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.AP-43	3.3.1-072	I, 3
47480	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.A-473a	3.3.1-160	I, 2
36670	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
36669	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
36668	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
37479	Heat Exchanger – (TBCW Heat Exchanger 12) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	None	None	VII.C1.A-47	3.3.1-072	I, 3
37425	Heat Exchanger – (TBCW Heat Exchanger 13) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
39113	Heat Exchanger – (TBCW Heat Exchanger 13) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36630	Heat Exchanger – (TBCW Heat Exchanger 13) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
39114	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Copper Alloy with less than 15% Zinc Cladding	Closed Cycle Cooling Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36652	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Copper Alloy with less than 15% Zinc Cladding	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-046	A
36639	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Copper Alloy with less than 15% Zinc Cladding	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
36640	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Copper Alloy with less than 15% Zinc Cladding	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
37427	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3.1-080	A
36633	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
36634	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
36635	Heat Exchanger – (TBCW Heat Exchanger 13) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
39009	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3.1-050	A
39008	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Heat Transfer	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3.1-042	A
39007	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3.1-046	A

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39006	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.AP-43	3.3.1-072	I, 3
49006	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (External)	None	None	VII.C2.A-473a	3.3.1-160	I, 2
39005	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3.1-160	A
39004	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
39003	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
39002	Heat Exchanger – (TBCW Heat Exchanger 13) Tubes	Pressure Boundary	Copper Alloy with 15% Zinc or More	Raw Water (Internal)	None	None	VII.C1.A-47	3.3.1-072	I, 3
36682	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
37579	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
36681	Hoses	Leakage Boundary (Spatial)	Elastomers	Closed Cycle Cooling Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C2.AP-259	3.3.1-085	A
36824	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
36823	Piping elements	Leakage Boundary (Spatial)	Glass	Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
36686	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39116	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36685	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
37440	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 4
37442	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37443	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-43	3.3.1-072	B
37441	Piping, piping components	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 2
36690	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39117	Piping, piping components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36692	Piping, piping components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36694	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3.1-004	B
36695	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3.1-006	B
36696	Piping, piping components	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-049	A
39118	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
37438	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
37439	Piping, piping components: Insulated	Leakage Boundary (Spatial)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
39119	Pump Casing (Chiller H2O Circulating Pump): Insulated	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
37433	Pump Casing (Chiller H2O Circulating Pump): Insulated	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
37434	Pump Casing (Chiller H2O Circulating Pump): Insulated	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
37435	Pump Casing (Chiller H2O Circulating Pump): Insulated	Leakage Boundary (Spatial)	Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36711	Pump Casing (Circulating Pump)	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39120	Pump Casing (Circulating Pump)	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36709	Pump Casing (Circulating Pump)	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36710	Pump Casing (Circulating Pump)	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
36704	Pump Casing (Turbine Building Cooling Water Pumps)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39121	Pump Casing (Turbine Building Cooling Water Pumps)	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36706	Pump Casing (Turbine Building Cooling Water Pumps)	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36707	Pump Casing (Turbine Building Cooling Water Pumps)	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
36742	Tanks (Closed Loop Cooling System Makeup Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
36825	Tanks (Closed Loop Cooling System Makeup Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Closed Cycle Cooling Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C2.A-416	3.3.1-138	B
36743	Tanks (Closed Loop Cooling System Makeup Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Closed Cycle Cooling Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.C2.A-414	3.3.1-139	B
38290	Tanks (Closed Loop Cooling System Makeup Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-401	3.2.1-072	B

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38273	Tanks (Closed Loop Cooling System Makeup Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-414	3.2.1-073	B
39122	Tanks (Surge Tank): Insulated	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36740	Tanks (Surge Tank): Insulated	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36739	Tanks (Surge Tank): Insulated	Leakage Boundary (Spatial)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3.1-132	A
38272	Tanks (Surge Tank): Insulated	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-26	3.3.1-055	A
36732	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39123	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36733	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36738	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39124	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36736	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36737	Valve Body	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
36726	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 4
36729	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36728	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-43	3.3.1-072	B
36727	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 2
36731	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
36730	Valve Body	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A
36717	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39125	Valve Body	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36718	Valve Body	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36716	Valve Body	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
39126	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
36714	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-045	A
36715	Valve Body	Pressure Boundary	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	B
36724	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
36723	Valve Body	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-046	A

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The turbine building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.
2. The turbine building closed loop cooling water system environment is a pure water chemistry-controlled environment where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.
3. TBCCW Heat Exchangers 11, 12, and 13 tubes are fabricated from admiralty brass (inhibited brass) and therefore per NUREG-2191 Table IX.C are not susceptible to selective leaching.

Table 3.3.2-20 Turbine Building Closed Loop Cooling System Summary of Aging Management Evaluation

4. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.3.2-21 Turbine Building HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33173	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33174	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3.1-015	B
38993	Bolting (Ducting Closure)	Mechanical Closure	Galvanized Bolting	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
33517	Bolting (Ducting Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Cracking	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3.1-145	B
33459	Bolting (Ducting Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3.1-012	B
33518	Ducting and Components	Pressure Boundary	Aluminum Alloy	Air - Outdoor (External)	None	None	VII.F2.A-451a	3.3.1-189	I, 1
33282	Ducting and Components	Pressure Boundary	Aluminum Alloy	Air - Outdoor (External)	none	None	VII.F2.A-763a	3.3.1-234	I, 1
33519	Ducting and Components	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	None	None	VII.F2.A-451a	3.3.1-189	I, 1
33283	Ducting and Components	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	none	None	VII.F2.A-763a	3.3.1-234	I, 1
33460	Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33461	Ducting and Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-08	3.3.1-090	A
33464	Ducting and Components	Pressure Boundary	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33462	Ducting and Components	Pressure Boundary	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-401	3.2.1-072	B
33463	Ducting and Components	Pressure Boundary	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	V.D2.E-414	3.2.1-073	B
33176	Ducting and Components	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C

Table 3.3.2-21 Turbine Building HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33177	Ducting and Components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-08	3.3.1-090	A
33600	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3.1-076	A
33602	Flexible Connection	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3.1-082	A
33598	Flexible Connection	Pressure Boundary	Elastomers	Condensation (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-504	3.3.1-085	A
33601	Flexible Connection	Pressure Boundary	Elastomers	Condensation (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)			H, 2
33178	Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F2.A-417	3.3.1-096b	A
33521	Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3.1-193	B
33179	Heat Exchanger – (Area Coolers) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-038	A
33180	Heat Exchanger – (Area Coolers) Tubes	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	A
33181	Heat Exchanger – (Area Coolers) Tubes	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-038	A
33213	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33214	Piping, piping components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-26	3.3.1-055	A
33522	Silencer / Muffler	Pressure Boundary	Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C

Table 3.3.2-21 Turbine Building HVAC System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33458	Silencer / Muffler	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-08	3.3.1-090	A
33218	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-078	A
33219	Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-26	3.3.1-055	A

Table 3.3.2-21 Turbine Building HVAC System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The diesel generator building ventilation system exhaust hoods for the roof mounted ventilation blower housings are constructed of 6061-T6x aluminum alloy which is not susceptible to stress corrosion cracking (NUREG-2192 Section 3.3.2.2.8). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, loss of material due to pitting and crevice corrosion need not be managed (NUREG-2192 Section 3.3.2.2.10).
2. This component/material/environment combination includes the aging effect of loss of material. This aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program.

3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEM

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 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.

- Condensate and Condensate Transfer System (2.3.4.1)
- Condenser Air Removal and Off-Gas System (2.3.4.2)
- Feedwater/High Pressure Coolant Injection System (2.3.4.3)
- Main Generator and Auxiliary System (2.3.4.4)
- Main Steam System (2.3.4.5)
- Main Turbine and Auxiliary System (2.3.4.6)

3.4.2 RESULTS

The following tables summarize the results of the aging management review for Steam and Power Conversion System.

Table 3.4.2-1 Condensate and Condensate Transfer System - Summary of Aging Management Evaluation

Table 3.4.2-2 Condenser Air Removal and Off-Gas System - Summary of Aging Management Evaluation

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System - Summary of Aging Management Evaluation

Table 3.4.2-4 Main Generator and Auxiliary System - Summary of Aging Management Evaluation

Table 3.4.2-5 Main Steam System - Summary of Aging Management Evaluation

Table 3.4.2-6 Main Turbine and Auxiliary System - Summary of Aging Management Evaluation

3.4.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.4.2.1.1 Condensate and Condensate Transfer System

Materials

The materials of construction for the Condensate and Condensate Transfer System components are:

- Aluminum Alloy

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel (with Internal Coatings)
- Cast Iron
- Copper Alloy with less than 15% Zinc
- Elastomers
- Glass
- Polymer
- Stainless Steel

Environments

The Condensate and Condensate Transfer System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Concrete
- Condensation
- Lubricating Oil
- Raw Water
- Treated Water
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Condensate and Condensate Transfer System components require management:

- Cracking
- Cracking or Blistering
- Cumulative Fatigue Damage
- Hardening or Loss of Strength Due to Elastomeric Degradation
- Hardening or Loss of Strength Due to Polymeric Degradation
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Material Due to Peeling, Delamination, Wear

- Loss of Material Due to Wear
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Condensate and Condensate Transfer System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Open-Cycle Cooling Water System (B.2.1.11)
- Selective Leaching (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.4.2.1.2 Condenser Air Removal and Off-Gas System

Materials

The materials of construction for the Condenser Air Removal and Off-Gas System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Stainless Steel

Environments

The Condenser Air Removal and Off-Gas System components are exposed to the following environments:

- Air - Indoor, Uncontrolled

- Treated Water
- Treated Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Condenser Air Removal and Off-Gas System components 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 Condenser Air Removal and Off-Gas System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- One-Time Inspection (B.2.1.20)
- TLAA
- Water Chemistry (B.2.1.2)

3.4.2.1.3 Feedwater/High Pressure Coolant Injection System

Materials

The materials of construction for the Feedwater/High Pressure Coolant Injection System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Stainless Steel

Environments

The Feedwater/High Pressure Coolant Injection System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Lubricating Oil
- Treated Water
- Treated Water > 140°F
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Feedwater/High Pressure Coolant Injection System components require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- 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 Feedwater/High Pressure Coolant Injection System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- TLAA
- Water Chemistry (B.2.1.2)

3.4.2.1.4 Main Generator and Auxiliary System

Materials

The materials of construction for the Main Generator and Auxiliary System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Cast Iron
- Glass
- Stainless Steel

Environments

The Main Generator and Auxiliary System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Closed Cycle Cooling Water
- Condensation
- Treated Water
- Treated Water > 140°F
- Waste Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Main Generator and Auxiliary System components 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 Main Generator and Auxiliary System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.4.2.1.5 Main Steam System

Materials

The materials of construction for the Main Steam System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Nickel Alloy
- Stainless Steel

Environments

The Main Steam System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Steam
- Treated Water
- Treated Water > 140°F

Aging Effect Requiring Management

The following aging effects associated with the Main Steam System components 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 components:

- Bolting Integrity (B.2.1.10)

- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- One-Time Inspection (B.2.1.20)
- TLAA
- Water Chemistry (B.2.1.2)

3.4.2.1.6 Main Turbine and Auxiliary System

Materials

The materials of construction for the Main Turbine and Auxiliary System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Stainless Steel

Environments

The Main Turbine and Auxiliary System components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Condensation
- Lubricating Oil
- Steam
- Treated Water
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Main Turbine and Auxiliary System components 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 Turbine and Auxiliary System components:

- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- TLAA
- Water Chemistry (B.2.1.2)

3.4.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Steam and Power Conversion System, those programs are addressed in the following subsections.

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). The evaluation of fatigue as a TLAA for the Condensate and Condensate Transfer, Condenser Air Removal and Off-Gas, Feedwater/High Pressure Coolant Injection, Main Steam, and Main Turbine and Auxiliary systems is discussed in Section 4.3.

3.4.2.2.2 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: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components, or (iv) 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. The SCC in SS components is not an aging effect which requires management if: (i) plant-specific OE does not reveal a history of SCC and (ii) a one-time inspection demonstrates that no aging effect is occurring or apparent.

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 cracking due to SCC: (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 (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 those 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 mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. 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.

Table 3.4.1 Item Number 3.4.1-002: This item evaluates cracking due to SCC in stainless steel piping, piping components, and tanks exposed to any air and condensation environments. Plant-specific operating experience (OE) from 2016 to 2026 associated with stainless steel components in the Steam and Power Conversion System has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been

experienced at NMP1 for stainless steel and CASS in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking is not occurring in stainless steel and CASS components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.4.1 Item Number 3.4.1-074: Not applicable. There are no stainless steel underground piping, piping components or tanks in the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-100: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-104: Not applicable. There are no insulated stainless steel piping, piping components, or tanks exposed to air, condensation in the Steam and Power Conversion System.

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: (i) uninsulated; (ii) insulated; (iii) in the vicinity of insulated components; or (iv) 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 parts 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 that requires management for SS and nickel-alloy components if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (ii) 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 in the presence 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 a SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or 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.

The applicant may mitigate or prevent loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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 for internal or external coatings.

Table 3.4.1 Item Number 3.4.1-003: This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components exposed to air and condensation environments. Plant-specific operating experience (OE) from 2016 to 2026 associated with stainless steel and nickel alloy components in the Steam and Power Conversion System has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for stainless steel and nickel alloy in these environments, or as a result of transportable halogens. This provides objective evidence that the internal and external surfaces of components in these environments are not

experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material is not occurring in stainless steel and nickel alloy components exposed to air-indoor uncontrolled and condensation environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

Table 3.4.1 Item Number 3.4.1-095: Not applicable. There are no stainless steel or nickel alloy underground piping, piping components, or tanks in the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-098: Not applicable. There are no stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-103: Not applicable. There are no insulated stainless steel or nickel alloy piping, piping components, or tanks exposed to air, condensation in the Steam and Power Conversion System.

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 Section B.1.3.

3.4.2.2.5 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.6 and Appendix B, Section B.1.4.

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: (i) a 10 year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (ii) 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 for implementing in more frequent inspections.

The applicant states: (i) 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, (ii) the basis for the adequacy of augmented or lack of augmented inspections, (iii) the trend of which parameters will be followed 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), (iv) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (v) 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° 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 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 environments other than raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Table 3.4.1 Item Number 3.4.1-061: This item evaluates loss of material due to recurring internal corrosion of carbon steel piping and piping components exposed to raw water. Plant-specific operating experience (OE) from 2016 to 2026 has identified recurring internal corrosion (RIC) in carbon steel piping and piping components exposed to raw water in the Condensate and Condensate Transfer System.

As described below, NMP1 will implement the Open-Cycle Cooling Water System (B.2.1.11) program to manage RIC in the Condensate and Condensate Transfer System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Open Cycle Cooling Water System (B.2.1.11) program is described in Appendix B.

- i. The program utilizes volumetric (e.g., UT) examination methods for the detection of aging effects. These conventional NDE methods quantitatively evaluate components to verify fitness for service and have been proven effective for the detection of aging effects prior to loss of intended function.
- ii. The Open Cycle Cooling Water System (B.2.1.11) program includes methodology for choosing piping inspection locations and the performance of volumetric inspections for various degradation mechanisms including RIC. The current

commitment for GL 89-13 does not include a specified number or location of volumetric examinations. Instead, the number and prioritization of inspection locations is based on the risk associated with specific pipe locations balanced by other factors to investigate and address potential piping integrity concerns. The risk is determined by the combination of piping corrosion susceptibility (based on water quality, pipe material, pipe size, flow velocity, operating frequency (i.e., stagnant or intermittent flow), piping configuration, internal blockages, and prior repairs) and the consequences of pipe leaks or other integrity issues (e.g., piping below minimum required thickness). The extent of the inspection scope and criteria used when selecting inspection locations may include: inspections required for extent of condition, inspections required based on the risk factor, re-inspection locations based on next scheduled inspection (NSI) calculations, new inspection locations based on Industry/fleet operating experience, and follow up inspections on weld repairs or branch connection/half coupling repairs. The selection of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure is an acceptable approach to address RIC as required by this Further Evaluation.

Additionally, the Open Cycle Cooling Water System (B.2.1.11) program will be enhanced to perform a minimum of 10 inspections for recurring internal corrosion in the raw water systems, including water based fire systems, every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for recurring internal corrosion. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of re-inspection interval.

- iii. The program includes trending of corrosion data and the decision point where increased inspections would be implemented.
 - The program includes guidance for the determination of the Next Scheduled Inspection (NSI). This is the calculated time frame at which an inspection will be performed on the component based on current measured corrosion rate trending.
 - For inspections that do not meet acceptance criteria, the following code and non-code examination scope expansion criteria is procedurally mandatory for plants within their subsequent period of extended operation. 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; then no fewer than five additional inspections will be performed for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections.

- iv. Components that are not easily accessed (i.e., buried) are included in the evaluation of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure. Opportunistic visual inspection of the internal surface of inaccessible piping is performed during maintenance activities that provide access to the internal surfaces of these lines.
- v. The NMP1 Condensate and Condensate Transfer System does not include buried components.

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 are provided for demonstrating that the specific material is not susceptible to SCC or the ambient environment is not aggressive in nature. Cracking due to SCC is an aging effect which requires management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

3.4.2.2.7.1 Susceptible Material

If the material is not susceptible to SCC, then cracking is not an aging effect that requires management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, that 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 type, 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 wt% 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 wt%*

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, 6063-T6, 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, and product form. For tempers not addressed above, the basis used to determine that the alloy is not susceptible and technical information substantiating the basis is added to the SLRA.

3.4.2.2.7.2 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 which requires management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys include the presence of 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 layer 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. 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. 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.

The applicant may mitigate or prevent cracking due to SCC through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify SCC as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous

solutions and 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 for internal or external coatings.

Table 3.4.1 Item Number 3.4.1-109: This item evaluates cracking due to SCC in aluminum alloy piping, piping components, and tanks exposed to air and condensation. Plant-specific operating experience (OE) from 2016 to 2026 associated with aluminum alloy components in the Steam and Power Conversion System has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of cracking is not occurring in aluminum alloy components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

The following component types in the identified systems are exposed to air-indoor uncontrolled and condensation but are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required.

- Condensate and Condensate Transfer System: The Resin add tank is constructed of 3003-H14 aluminum alloy.
- Condensate and Condensate Transfer System: Aluminum alloy valve bodies with a pressure boundary function that are 2.5 inches or larger are constructed of 6061 T6 aluminum alloy.

Table number 3.4.1 Item Number 3.4.1-102: This item evaluates cracking due to SCC in aluminum alloy tanks exposed to air, condensation, and concrete. Plant-specific operating experience (OE) from 2016 to 2026 associated with aluminum alloy components in the Steam and Power Conversion System has been evaluated to determine if prolonged exposure to the environments of air, condensation, and concrete has resulted in cracking due to SCC. Cracking has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in cracking.

All components addressed by Item Number 3.4.1-102 in the identified system are exposed to air-indoor uncontrolled, concrete, and condensation environments. These

components are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required.

- Condensate and Condensate Transfer System: The Condensate Surge and Storage tanks are constructed of 5052-H34 aluminum alloy.

Table 3.4.1 Item Number 3.4.1-105: Not applicable. There are no insulated aluminum piping, piping components, or tanks exposed to air, condensation in the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-112: Not applicable. There are no 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 highly alkaline 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 highly alkaline 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 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 penetrate 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: (i) attributes of the concrete are consistent with ACI 318 (ACI 1997-TN8116) or ACI 349 (ACI 1985-TN8165) (low water to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557 (NRC 1996-TN8063); (ii) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (iii) 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.

Table 3.4.1 Item Number 3.4.1-051: Not applicable. There are no steel piping, piping components exposed to concrete in the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-082: Not applicable. There are no stainless steel piping, piping components exposed to concrete in the Steam and Power Conversion System.

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 greatly depend 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 which requires management for aluminum alloys if: (i) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (ii) 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. Alternatively, loss of material due to pitting and crevice corrosion need not be managed if the type of aluminum is not susceptible to cracking and plant-specific operating experience does not reveal any issues related to loss of material due to pitting or crevice corrosion. 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 in the presence 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. The 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 a 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.

The applicant may mitigate or prevent the loss of material due to pitting and crevice corrosion through the use of a barrier coating to isolate the component from aggressive environments. However, the applicant should identify loss of material as applicable for SLR and identify the AMP that will be used to manage the integrity of the coating. 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,” or equivalent program, describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Table 3.4.1 Item Number 3.4.1-035: This item evaluates loss of material due to pitting and crevice corrosion in aluminum piping, piping components, and tanks exposed to air and condensation. Plant-specific operating experience (OE) from 2016 to 2026 associated with aluminum alloy components in the Steam and Power Conversion System has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material. Accordingly, NMP1 will implement the One-Time Inspection (B.2.1.20) program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring in aluminum alloy components exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection (B.2.1.20) program is described in Appendix B.

The following component types in the identified systems are exposed to air and condensation, but are constructed of aluminum alloys that are not susceptible to loss of material (LOM). Therefore, LOM is not a predicted aging effect and aging management of these components for LOM is not required. As the components are not susceptible to cracking and plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion, loss of material due to pitting and crevice corrosion need not be managed.

- Condensate and Condensate Transfer System: The Resin add tank is constructed of 3003-H14 aluminum alloy.
- Condensate and Condensate Transfer System: Aluminum alloy valve bodies with a pressure boundary function that are 2.5 inches or larger are constructed of 6061 T6 aluminum alloy.

Table 3.4.1 Item Number 3.4.1-094: Not applicable. There are no aluminum underground piping, piping components, and tanks in Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-097: This item evaluates loss of material due to pitting and crevice corrosion in aluminum piping, piping components, and tanks exposed to air and condensation. Plant-specific operating experience (OE) from 2016 to 2026 associated with aluminum alloy components in the Steam and Power Conversion System has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified through this review as an aging effect that has been experienced at NMP1 for aluminum alloy in these environments, or as a result of exposure to secondary sources of halides. This provides objective evidence that the internal and external surfaces of components in these environments are not experiencing significant halide (e.g., chloride) contamination in the presence of moisture that would result in loss of material.

All components addressed in Item Number 3.4.1-097 are exposed to an air-indoor uncontrolled environment. These components are constructed of aluminum alloys that are not susceptible to SCC. Therefore, SCC is not a predicted aging effect and aging management of these components for SCC is not required. As the components are not susceptible to cracking and plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion, loss of material due to pitting and crevice corrosion need not be managed.

- Condensate surge and storage aluminum tanks: Components are constructed of a 5052-H34 aluminum alloy.

Table 3.4.1 Item Number 3.4.1-119: Not applicable. There are no insulated aluminum piping, piping components, or tanks exposed to air or condensation in the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4.1-120: Not applicable. There are no aluminum piping, piping components, or tanks exposed to raw water or waste water in the Steam and Power Conversion System.

3.4.2.3 **Time-Limited Aging Analysis**

The time-limited aging analyses identified below are associated with the Steam and Power Conversion System components:

- Section 4.3, Metal Fatigue Analyses

- Section 4.3.4, ASME Section III, Class 2 and 3, and ANSI B31.1 Allowable Stress Analyses and HELB Exclusions of Recirculation Piping Analysis

3.4.3 CONCLUSION

The Steam and Power Conversion System piping, fittings, and components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Steam and Power Conversion System components are identified in the summaries in Section 3.4.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Steam and Power Conversion System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-001	Steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, Standard Review Plan for Review of Subsequent License Renewal (SRP-SLR) Section 4.3 "Metal Fatigue"	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 3.4.2.2.1.
3.4.1-002	Stainless steel (SS) piping, piping components, tanks exposed to air, condensation	Cracking due to stress corrosion cracking (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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the stainless steel expansion joints, flow devices, heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to air - indoor, uncontrolled and condensation in the Radioactive Waste System, Condensate and Condensate Transfer System, Feedwater/High Pressure Coolant Injection System, Main Generator and Auxiliary System, Main Steam System, and Main Turbine and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.4.2.2.2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-003	SS, 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the nickel alloy and stainless steel expansion joints, flow device, heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to air - indoor, uncontrolled and condensation in the Condensate and Condensate Transfer System, Feedwater/High Pressure Coolant Injection System, Main Generator and Auxiliary System, Main Steam System, and Main Turbine and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.4.2.2.3.
3.4.1-004	PWR Only				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 with exceptions. The Flow-Accelerated Corrosion (B.2.1.9) program will be used to manage wall thinning of the carbon steel flow devices, piping, piping components, and valve bodies exposed to steam and treated water in the Reactor Water Cleanup, Reactor Coolant Pressure Boundary System, Condensate and Condensate Transfer System, Feedwater/High Pressure Coolant Injection System, Main Steam System, and Main Turbine and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for Flow-Accelerated Corrosion (B.2.1.9) program implementation.
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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of preload of the carbon and low alloy steel closure bolting exposed to air - indoor, uncontrolled in the Condensate and Condensate Transfer System, Condenser Air Removal and Off-Gas System, Feedwater/High Pressure Coolant Injection System, Main Generator and Auxiliary System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-007	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not Applicable. There is no high-strength steel closure bolting exposed to air, soil, or underground in the Steam and Power Conversion System.
3.4.1-008	This Item Number is not listed in NUREG-2192.				
3.4.1-009	Steel, SS, 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 with exceptions. The Bolting Integrity (B.2.1.10) program will be used to manage loss of material of the carbon and low alloy steel closure bolting exposed to air - indoor, uncontrolled in the Condensate and Condensate Transfer System, Condenser Air Removal and Off-Gas System, Feedwater/High Pressure Coolant Injection System, Main Generator and Auxiliary System, Main Steam System, and Main Turbine and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for Bolting Integrity (B.2.1.10) program implementation.
3.4.1-010	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-011	SS 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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage cracking of the cast austenitic stainless steel (CASS) and stainless steel expansion joints, heat exchanger components, piping, piping components, and valve bodies exposed to steam and treated water > 140°F in the Reactor Coolant Pressure Boundary System, Condenser Air Removal and Off-Gas System, Feedwater/High Pressure Coolant Injection System, Main Generator and Auxiliary System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-012	Steel tanks exposed to treated water	Loss of material due to general, pitting, crevice corrosion, microbiologically influenced corrosion (MIC)	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel tanks exposed to treated water in the Condensate and Condensate Transfer System and Feedwater/High Pressure Coolant Injection System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-013	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel and cast iron flow devices, piping, piping components, and valve bodies exposed to steam, treated water in the Reactor Coolant Pressure Boundary System, Condensate and Condensate Transfer System, Condenser Air Removal and Off-Gas System, Feedwater/High Pressure Coolant Injection System, Main Steam System, and Main Turbine and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the carbon steel heat exchanger components exposed to treated water in the Condensate and Condensate Transfer System, Condenser Air Removal and Off-Gas System, and Feedwater/High Pressure Coolant Injection System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-016	Copper alloy, aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the aluminum alloy piping, piping components, tanks, and valve bodies exposed to treated water in the Condensate and Condensate Transfer System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-017	This Item Number is not listed in NUREG-2192.				
3.4.1-018	Copper alloy, SS heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage reduction of heat transfer of the copper alloy heat exchanger tubes exposed to treated water in the Spent Fuel Pool Cooling and Storage System, Core Spray System, and Control Rod Drive System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-019	SS, steel heat exchanger components exposed to raw water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no stainless steel or steel heat exchanger components exposed to raw water in Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-020	Copper alloy, SS 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. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage loss of material of the stainless steel valve bodies exposed to raw water in the Condensate and Condensate Transfer System.
3.4.1-021	This Item Number is not listed in NUREG-2192.				
3.4.1-022	SS, 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	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage reduction of heat transfer of the copper alloy with less than 15% zinc heat exchanger tubes exposed to raw water in the Containment Spray System.
3.4.1-023	SS piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable There are no stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Steam and Power Conversion System.
3.4.1-024	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-025	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the carbon steel and cast iron heat exchanger components exposed to closed cycle cooling water in the Feedwater/High Pressure Coolant Injection System and Main Generator and Auxiliary System.
3.4.1-026	SS heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion System.
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. The Closed Treated Water Systems (B.2.1.12) program will be used to manage loss of material of the copper alloy with 15% zinc or more and copper alloy with less than 15% zinc heat exchanger components exposed to closed cycle cooling water in the Condensate and Condensate Transfer System and Feedwater/High Pressure Coolant Injection System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-028	Steel, SS, 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	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.1.12) program will be used to manage reduction of heat transfer of the carbon steel and copper alloy with less than 15% zinc heat exchanger tubes and shell side components exposed to closed cycle cooling water in the Condensate and Condensate Transfer System and Feedwater/High Pressure Coolant Injection System.
3.4.1-029	This Item Number is not listed in NUREG-2192.				
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	Not Applicable. There are no 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 Steam and Power Conversion System.
3.4.1-031	This Item Number is not listed in NUREG-2192.				
3.4.1-032	Gray cast iron, ductile iron, malleable iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no gray cast iron, ductile iron, or malleable iron piping, piping components exposed to soil in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-033	Gray cast iron, ductile iron, malleable iron, copper alloy (>15% zinc [Zn] or >8% aluminum [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 with exceptions. The Selective Leaching (B.2.1.21) program will be used to manage loss of material of the cast iron and copper alloy with 15% zinc or more heat exchanger components and pump casings exposed to closed cycle cooling water and treated water in the Condensate and Condensate Transfer System and Feedwater/High Pressure Coolant Injection System. Exceptions apply to the NUREG-2191 recommendations for the Selective Leaching (B.2.1.21) program implementation.
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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of the carbon steel, carbon steel (with internal coatings), and cast iron drip pans, flow devices, heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to air - indoor, uncontrolled in the Condensate and Condensate Transfer System, Condenser Air Removal and Off-Gas System, Feedwater/High Pressure Coolant Injection System, Main Generator and Auxiliary System, Main Steam System, and Main Turbine and Auxiliary System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-035	Al 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage loss of material of the aluminum alloy piping, piping components, and valve bodies exposed to air - indoor, uncontrolled in the Condensate and Condensate Transfer System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 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. There are no steel piping, piping components exposed to air – outdoor in the Steam and Power Conversion System.
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage loss of material of the carbon steel tanks exposed to condensation in the Feedwater/High Pressure Coolant Injection System and Main Turbine and Auxiliary System.
3.4.1-038	PWR Only				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-039	This Item Number is not listed in NUREG-2192.				
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,"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the carbon steel and cast iron piping, piping components, pump casings, tanks, and valve bodies exposed to lubricating oil in the Feedwater/High Pressure Coolant Injection System and Main Turbine and Auxiliary System.
3.4.1-041	PWR Only				
3.4.1-042	PWR Only				
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,"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the copper alloy with 15% zinc or more and copper alloy with less than 15% zinc heat exchanger components exposed to lubricating oil in the Condensate and Condensate Transfer System and Feedwater/High Pressure Coolant Injection System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-044	SS 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,"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.1.25) program will be used to manage loss of material of the stainless steel piping, piping components and strainer elements exposed to lubricating oil in the Feedwater/High Pressure Coolant Injection System and Main Turbine and Auxiliary System.
3.4.1-045	Al heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis,"	No	Not Applicable. There are no aluminum heat exchanger tubes exposed to lubricating oil in the Steam and Power Conversion System.
3.4.1-046	PWR Only				
3.4.1-047	SS piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no stainless steel piping, piping components, tanks, or closure bolting exposed to soil, concrete in the Steam and Power Conversion System.
3.4.1-048	Nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There are no nickel alloy piping, piping components, tanks, or closure bolting exposed to soil, concrete in the Steam and Power Conversion System.
3.4.1-049	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Not Applicable. There are no steel piping, piping components, tanks, or closure bolting exposed to soil, concrete, underground in the Steam and Power Conversion System.
3.4.1-050a	This Item Number is not listed in NUREG-2192.				
3.4.1-051	Steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no steel piping, piping components exposed to concrete in the Steam and Power Conversion System. See Subsection 3.4.2.2.8.
3.4.1-052	Al piping, piping components exposed to gas	None	None	No	Not Applicable. There are no aluminum piping, piping components exposed to gas in the Steam and Power Conversion System.
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. There are no copper alloy or copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. There are no nickel alloy piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System.
3.4.1-057	Polyvinyl chloride (PVC) piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not Applicable. There are no polyvinyl chloride (PVC) piping, piping components exposed to air – indoor uncontrolled, condensation in the Steam and Power Conversion System.
3.4.1-058	SS piping, piping components exposed to gas	None	None	No	Not Applicable. There are no stainless steel piping, piping components exposed to gas in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not Applicable. There are no steel piping, piping components exposed to air – indoor controlled or gas in the Steam and Power Conversion System.
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	Not Applicable. There are no metallic piping, piping components exposed to steam or treated water with the aging effect/mechanism of wall thinning due to erosion in the Steam and Power Conversion System.
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	Consistent with NUREG-2191. The Open-Cycle Cooling Water System (B.2.1.11) program will be used to manage loss of material of the carbon steel piping, piping components exposed to raw water in the Condensate and Condensate Transfer System. See Subsection 3.4.2.2.6.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-062	Steel, SS 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, SS only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. No aging management program required. Loss of material of aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water is not an applicable aging effect since these tanks are constructed of aluminum alloy that is not susceptible to loss of material (5052-H34), the treated water environment is not aggressive with the specific aluminum alloy, and plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion.
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	Not Applicable. There are no insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, or tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-064	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage reduced thermal insulation resistance of the asbestos, calcium silicate, and fiberglass insulation - thermal exposed to air - indoor, uncontrolled and air - outdoor in the Structural Commodity Group.
3.4.1-065	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-066	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, lubricating oil	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program will be used to manage loss of coating or lining integrity of the carbon steel (with internal coatings) tanks (Condensate Demineralizers) exposed to treated water in the Condensate and Condensate Transfer System. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program implementation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) has been substituted and will be used to manage loss of coating or lining integrity of the carbon steel (with internal coatings) tank (Resin Heater Tank) exposed to treated water in the Condensate and Condensate Transfer System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program will be used to manage loss of material of the carbon steel (with internal coatings) tanks (Condensate Demineralizers) exposed to treated water in the Condensate and Condensate Transfer System. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program implementation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) has been substituted and will be used to manage loss of material of the carbon steel (with internal coatings) tank (Resin Heater Tank) exposed to treated water in the Condensate and Condensate Transfer System.
3.4.1-068	Gray cast iron, ductile iron, malleable iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not Applicable. There are no gray cast iron, ductile iron, or malleable 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.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-069	This Item Number is not listed in NUREG-2192.				
3.4.1-070	SS, steel, nickel-alloy, copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water, waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Not Applicable. There are no 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.
3.4.1-071	This Item Number is not listed in NUREG-2192.				
3.4.1-072	SS, steel, Al 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 Used. Cracking due to SCC (steel in carbonate/bicarbonate environment only) in the stainless steel, steel, and aluminum piping, piping components, and tanks exposed to soil, concrete is addressed by item numbers 3.4.1-96 and 3.4.1-102.
3.4.1-073	SS closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Not Applicable. There is no stainless steel closure bolting exposed to air, soil, concrete, underground, or waste water in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-074	SS 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	Not Applicable. There are no stainless steel underground piping, piping components, or tanks in the Steam and Power Conversion System. See Subsection 3.4.2.2.2.
3.4.1-075	SS, steel, Al, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes exposed to air, condensation with a heat transfer intended function in the Steam and Power Conversion System.
3.4.1-076	This Item Number is not listed in NUREG-2192.				
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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage hardening or loss of strength due to elastomeric degradation of the elastomer expansion joints and hoses exposed to air - indoor, uncontrolled in the Condensate and Condensate Transfer System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-078	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Used. Hardening or loss of strength due to elastomer degradation of elastomer expansion joints and hoses exposed to air - indoor, uncontrolled is addressed by item number 3.4.1-077. There are no elastomer piping, piping components, or seals exposed to condensation in the Steam and Power Conversion System.
3.4.1-079	This Item Number is not listed in NUREG-2192.				
3.4.1-080	This Item Number is not listed in NUREG-2192.				
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 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage long-term loss of material of the carbon steel and cast iron flow devices, heat exchanger components, piping, piping components, pump casings, tanks, and valve bodies exposed to raw water and treated water in the Condensate and Condensate Transfer System, Condenser Air Removal and Off-Gas System, Feedwater/High Pressure Coolant Injection System, Main Steam System, and Main Turbine and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-082	SS piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no stainless steel piping, piping components exposed to concrete in the Steam and Power Conversion System. See Subsection 3.4.2.2.8.
3.4.1-083	SS, nickel-alloy tanks exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the stainless steel tanks exposed to treated water in the Main Generator and Auxiliary System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-084	SS, nickel-alloy piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the cast austenitic stainless steel (CASS) and stainless steel piping, piping components and valve bodies, exposed to steam in the Reactor Coolant Pressure Boundary System and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-085	SS, 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"	No	Consistent with NUREG-2191 with exceptions. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of the nickel alloy and stainless steel expansion joints, flow devices, heat exchanger components, piping, piping components, pump casings, strainer elements, and valve bodies exposed to treated water in the Condensate and Condensate Transfer System, Condenser Air Removal and Off-Gas System, Feedwater/High Pressure Coolant Injection System, Main Generator and Auxiliary System, and Main Steam System. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.
3.4.1-086	SS, steel, Al, copper alloy, titanium heat exchanger tubes internal to components exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no stainless steel piping, piping components exposed to concrete in the Steam and Power Conversion System.
3.4.1-087	This Item Number is not listed in NUREG-2192.				
3.4.1-088	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-089	Steel, SS, copper alloy piping, piping components exposed to raw water (for components not covered by U.S. Nuclear Regulatory Commission [NRC] Generic Letters [GL] 89-13).	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel, stainless steel, or copper alloy piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Steam and Power Conversion System.
3.4.1-090	Steel, SS, copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel, stainless steel, or copper alloy heat exchanger tubes exposed to raw water in the Steam and Power Conversion System.
3.4.1-091	Steel, SS, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel, stainless steel, or copper alloy heat exchanger components exposed to raw water in Steam and Power Conversion System.
3.4.1-092	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Steam and Power Conversion System.
3.4.1-093	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. There are no aluminum underground piping, piping components, or tanks in the Steam and Power Conversion System. See Subsection 3.4.2.2.9.
3.4.1-095	SS, 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	Not Applicable. There are no stainless steel or nickel alloy underground piping, piping components, or tanks in the Steam and Power Conversion System. See Subsection 3.4.2.2.3.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-096	Al 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	Consistent with NUREG-2191. No aging management program required. Loss of material of aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to concrete is not an applicable aging effect since these tanks are constructed of aluminum alloy that is not susceptible to cracking (5052-H34), the concrete environment is not aggressive, and plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion.
3.4.1-097	Al 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	Consistent with NUREG-2191. No aging management program required. See Subsection 3.4.2.2.9.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-098	SS, 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	Not Applicable. There are no stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in the Steam and Power Conversion System. See Subsection 3.4.2.2.3.
3.4.1-099	SS tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete in the Steam and Power Conversion System.
3.4.1-100	SS 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	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation in the Steam and Power Conversion System. See Subsection 3.4.2.2.2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-101	SS tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete in the Steam and Power Conversion System.
3.4.1-102	Al 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	Consistent with NUREG-2191. No aging management program required. See Subsection 3.4.2.2.7.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-103	Insulated SS, 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	Not Applicable. There are no insulated stainless steel or nickel alloy piping, piping components, or tanks exposed to air, condensation in the Steam and Power Conversion System. See Subsection 3.4.2.2.3.
3.4.1-104	Insulated SS 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	Not Applicable. There are no insulated stainless steel piping, piping components, or tanks exposed to air, condensation in the Steam and Power Conversion System. See Subsection 3.4.2.2.2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-105	Insulated Al 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	Not Applicable. There are no insulated aluminum piping, piping components, or tanks exposed to air, condensation in the Steam and Power Conversion System. See Subsection 3.4.2.2.7.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking of the copper alloy with 15% zinc or more heat exchanger components, hoses, piping, piping components, spray nozzles and valve bodies exposed to air - indoor, uncontrolled and condensation in the Circulating Water System, City Water System, Compressed Air Systems, Containment Systems, Emergency Diesel Generator System, Fire Detection and Protection System, Makeup Demineralizer System, Reactor Building Closed Loop Cooling System, Reactor Water Cleanup, Turbine Building Closed Loop Cooling System, Control Rod Drive System, and Feedwater/High Pressure Coolant Injection System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation.
3.4.1-107	Copper alloy (>15% Zn or >8% Al) tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no copper alloy with 15% zinc or more tanks exposed to air, condensation in the Steam and Power Conversion System.
3.4.1-108	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-109	Al 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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20) program will be used to manage cracking of the aluminum alloy piping, piping components exposed to air - indoor, uncontrolled in the Condensate and Condensate Transfer System. Exceptions apply to the NUREG-2191 recommendations for One-Time Inspection (B.2.1.20) program implementation. See Subsection 3.4.2.2.7.
3.4.1-110	This Item Number is not listed in NUREG-2192.				
3.4.1-111	This Item Number is not listed in NUREG-2192.				
3.4.1-112	Al 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	Not Applicable. There are no aluminum underground piping, piping components, or tanks in the Steam and Power Conversion System. See Subsection 3.4.2.2.7.
3.4.1-113	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to treated water in the Steam and Power Conversion System.
3.4.1-115	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not Applicable. There are no titanium heat exchanger components other than tubes or piping, piping components exposed to treated water in the Steam and Power Conversion System.
3.4.1-116	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There are no titanium heat exchanger tubes exposed to closed-cycle cooling water in the Steam and Power Conversion System.
3.4.1-117	Al 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 Used. Loss of material due to pitting, crevice corrosion of aluminum tanks exposed to concrete is addressed by item number 3.4.1-096. There are no piping, piping components, or tanks exposed to soil in the Steam and Power Conversion System.
3.4.1-118	This Item Number is not listed in NUREG-2192.				

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-119	Insulated Al 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	Not Applicable. There are no insulated aluminum piping, piping components, or tanks exposed to air, condensation in Steam and Power Conversion System. See Subsection 3.4.2.2.9.
3.4.1-120	Al 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	Not Applicable. There are no aluminum piping, piping components, or tanks exposed to raw water or waste water in the Steam and Power Conversion System. See Subsection 3.4.2.2.9.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-121	This Item Number is not listed in NUREG-2192.				
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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material due to wear of the elastomer expansion joints and hoses exposed to air - indoor, uncontrolled in the Condensate and Condensate Transfer System.
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 Used. Loss of material due to wear of the elastomer expansion joints and hoses exposed to air is addressed by item number 3.4.1-122
3.4.1-124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not Applicable. There are no PVC piping, piping components, or tanks exposed to concrete in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-125	PVC, carbon fiber reinforced polymer (CFRP) piping, piping components, tanks exposed to soil	Cracking, blistering, loss of material due to wear, tearing, delamination, void, debonding, chemical attack and exposure to moisture; flow blockage due to fouling, delamination, debonding, or tearing	AMP XI.M41, "Buried and Underground Piping and Tanks" or AMP XI.M43, "High Density Polyethylene (HDPE) Piping and Carbon Fiber Reinforced Polymer (CFRP) Repaired Piping"	No	Not Applicable. There are no PVC or carbon fiber reinforced polymer (CFRP) piping, piping components, or tanks exposed to soil in the Steam and Power Conversion System.
3.4.1-126	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not Applicable. There are no 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.
3.4.1-127	Al piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, or tanks exposed to air with borated water leakage in the Steam and Power Conversion System.
3.4.1-128	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There are no copper alloy piping, piping components exposed to concrete in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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. There are no copper alloy piping, piping components exposed to soil, underground in the Steam and Power Conversion System.
3.4.1-130	Titanium piping, piping components, heat exchanger components other than tubes exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no titanium piping, piping components, or heat exchanger components other than tubes exposed to raw water in the Steam and Power Conversion System.
3.4.1-131	PWR Only				
3.4.1-132	PWR Only				
3.4.1-133	Al piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no aluminum piping, piping components exposed to raw water in the Steam and Power Conversion System.
3.4.1-134	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in the Steam and Power Conversion System.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 (Inspection of Internal Surfaces only)	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. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program will be used to manage cracking or blistering, hardening or loss of strength due to polymeric degradation, loss of material due to peeling, delamination, and wear of the polymer piping, piping components and valve bodies exposed to air - indoor, uncontrolled, treated water, and waste water in the Condensate and Condensate Transfer System.

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37021	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
37020	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
37162	Expansion Joints	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-428	3.4.1-077	A
37161	Expansion Joints	Pressure Boundary	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-471	3.4.1-122	A
37163	Expansion Joints	Pressure Boundary	Elastomers	Treated Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-75	3.3.1-085	A
37164	Expansion Joints	Pressure Boundary	Elastomers	Treated Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-76	3.3.1-096	A
38187	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
38188	Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4.1-003	B
38189	Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
38191	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
38192	Flow Device	Throttle	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4.1-003	B
38193	Flow Device	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
38180	Heat Exchanger – (Condensate Pump Coolers) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-57	3.4.1-028	A
38181	Heat Exchanger – (Condensate Pump Coolers) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	VII.C2.A-791	3.3.1-257	A
38179	Heat Exchanger – (Condensate Pump Coolers) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-8	3.4.1-027	C
38178	Heat Exchanger – (Condensate Pump Coolers) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.E.SP-92	3.4.1-043	C

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37165	Heat Exchanger – (Main Condenser Hotwell) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37166	Heat Exchanger – (Main Condenser Hotwell) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
37167	Heat Exchanger – (Main Condenser Hotwell) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
37170	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Elastomeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-428	3.4.1-077	A
37169	Hoses	Leakage Boundary (Spatial)	Elastomers	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-471	3.4.1-122	A
37172	Hoses	Leakage Boundary (Spatial)	Elastomers	Treated Water (Internal)	Hardening or Loss of Strength Due to Elastomeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-75	3.3.1-085	A
37171	Hoses	Leakage Boundary (Spatial)	Elastomers	Treated Water (Internal)	Loss of Material Due to Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-76	3.3.1-096	A
38182	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VIII.I.SP-33	3.4.1-055	A
38183	Piping elements	Leakage Boundary (Spatial)	Glass	Treated Water (Internal)	None	None	VIII.I.SP-35	3.4.1-055	A
37210	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.S-457b	3.4.1-109	B, 3
37211	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-147a	3.4.1-035	B
37209	Piping, piping components	Leakage Boundary (Spatial)	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-90	3.4.1-016	B
37217	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37221	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37222	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37223	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material/Recurring Internal Corrosion	Open-Cycle Cooling Water System (B.2.1.11)	VIII.E.S-400a	3.4.1-061	A
37220	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
37219	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
37224	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
37227	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37207	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4.1-135	A
37205	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4.1-135	A
37206	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4.1-135	A
38184	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Treated Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
38185	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Treated Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
38961	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37201	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
37202	Piping, piping components	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
37212	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
37213	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4.1-003	B
37214	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
37215	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A
37354	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.S-457b	3.4.1-109	B, 3
37355	Piping, piping components	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-147a	3.4.1-035	B
37356	Piping, piping components	Pressure Boundary	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-90	3.4.1-016	B
37360	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37365	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
37364	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
37404	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.E.S-16	3.4.1-005	B
37366	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
37367	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4.1-003	B
37368	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36869	Pump Casing (Condensate Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
36870	Pump Casing (Condensate Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
36871	Pump Casing (Condensate Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
36872	Pump Casing (Condensate Transfer Pumps)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
36873	Pump Casing (Condensate Transfer Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
36874	Pump Casing (Condensate Transfer Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
36875	Pump Casing (Condensate Transfer Pumps)	Pressure Boundary	Cast Iron	Treated Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-27	3.4.1-033	B
37182	Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
36880	Tanks (Condensate Demineralizers)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
36878	Tanks (Condensate Demineralizers)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VIII.E.S-401	3.4.1-066	B
36877	Tanks (Condensate Demineralizers)	Pressure Boundary	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VIII.E.S-414	3.4.1-067	B
36996	Tanks (Condensate Prefilters)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
36997	Tanks (Condensate Prefilters)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
36998	Tanks (Condensate Prefilters)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-75	3.4.1-012	B

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38996	Tanks (Condensate Surge & Storage Tank)	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	VIII.E.S-445b	3.4.1-097	I, 1
37196	Tanks (Condensate Surge & Storage Tank)	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	VIII.E.S-450a	3.4.1-102	I, 1
38995	Tanks (Condensate Surge & Storage Tank)	Pressure Boundary	Aluminum Alloy	Concrete (External)	none	None	VIII.E.S-444	3.4.1-096	I, 1
38994	Tanks (Condensate Surge & Storage Tank)	Pressure Boundary	Aluminum Alloy	Concrete (External)	None	None	VIII.E.S-450a	3.4.1-102	I, 1
37198	Tanks (Condensate Surge & Storage Tank)	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	None	None	VIII.E.S-450a	3.4.1-102	I, 1
38275	Tanks (Condensate Surge & Storage Tank)	Pressure Boundary	Aluminum Alloy	Condensation (Internal)	none	None	VIII.E.S-445b	3.4.1-097	I, 1
38997	Tanks (Condensate Surge & Storage Tank)	Pressure Boundary	Aluminum Alloy	Treated Water (Internal)	None	None	VIII.E.S-405	3.4.1-062	I, 1
38417	Tanks (Head Tank)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
38419	Tanks (Head Tank)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
38420	Tanks (Head Tank)	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37002	Tanks (Resin Add Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	VIII.E.S-457b	3.4.1-109	I, 5
37003	Tanks (Resin Add Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	VIII.E.SP-147a	3.4.1-035	I, 5
38475	Tanks (Resin Add Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Condensation (Internal)	None	None	VIII.E.S-457b	3.4.1-109	I, 5
38476	Tanks (Resin Add Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Condensation (Internal)	none	None	VIII.E.SP-147a	3.4.1-035	I, 5
38477	Tanks (Resin Add Tank)	Leakage Boundary (Spatial)	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-90	3.4.1-016	B
36999	Tanks (Resin Heater Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38422	Tanks (Resin Heater Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-401	3.2.1-072	E, 6
37007	Tanks (Resin Heater Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-414	3.2.1-073	E, 6
38485	Tanks (Resin Heater Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-401	3.4.1-066	E, 6
38486	Tanks (Resin Heater Tank)	Leakage Boundary (Spatial)	Carbon Steel (with Internal Coatings)	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-414	3.4.1-067	E, 6
38426	Valve Body	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-147a	3.4.1-035	B
38425	Valve Body	Leakage Boundary (Spatial)	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	VIII.E.S-457b	3.4.1-109	I, 2
38427	Valve Body	Leakage Boundary (Spatial)	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-90	3.4.1-016	B
37331	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37333	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
37334	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-037	A
37336	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
37335	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
37337	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37338	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
37342	Valve Body	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Cracking or Blistering	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4.1-135	A
37340	Valve Body	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Hardening or Loss of Strength Due to Polymeric Degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4.1-135	A
37341	Valve Body	Leakage Boundary (Spatial)	Polymer	Air - Indoor, Uncontrolled (External)	Loss of Material Due to Peeling, Delamination, Wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4.1-135	A
38198	Valve Body	Leakage Boundary (Spatial)	Polymer	Treated Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
38199	Valve Body	Leakage Boundary (Spatial)	Polymer	Treated Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
38962	Valve Body	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Cracking or Blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
37343	Valve Body	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Hardening or Loss of Strength Due to Polymeric Degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
37344	Valve Body	Leakage Boundary (Spatial)	Polymer	Waste Water (Internal)	Loss of Material Due to Peeling, Delamination, Wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4.1-135	A
37349	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
37350	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4.1-003	B
38201	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VIII.E.SP-36	3.4.1-020	A

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39034	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 4
37351	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B
37352	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A
37357	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	None	None	VIII.E.S-457b	3.4.1-109	I, 2
38277	Valve Body	Pressure Boundary	Aluminum Alloy	Air - Indoor, Uncontrolled (External)	none	None	VIII.E.SP-147a	3.4.1-035	I, 2
37359	Valve Body	Pressure Boundary	Aluminum Alloy	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-90	3.4.1-016	B
37371	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37376	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
37375	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
37405	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.E.S-16	3.4.1-005	B
37377	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4.1-002	B
37378	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4.1-003	B
39035	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 4
37379	Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-085	B

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. Components constructed of 5052-H34 aluminum alloy contain less than 3.5 weight percent of magnesium and therefore are not susceptible to stress corrosion cracking (NUREG-2192 Section 3.4.2.2.7). Concrete and treated water environments are not aggressive, and plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, loss of material due to pitting and crevice corrosion need not be managed (NUREG-2192 Section 3.4.2.2.9).
2. Components constructed of 6061-T6 aluminum alloy are not susceptible to stress corrosion cracking (NUREG-2192 Section 3.4.2.2.7). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, loss of material due to pitting and crevice corrosion need not be managed (NUREG-2192 Section 3.4.2.2.9).
3. Components constructed of 5086 aluminum alloy contain greater than 3.5 weight percent of magnesium, and therefore are susceptible to stress corrosion cracking (NUREG-2192 Section 3.4.2.2.7).
4. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.4.2-1 Condensate and Condensate Transfer System Summary of Aging Management Evaluation

5. Components are constructed of a 3xxx series aluminum alloy which is not susceptible to stress corrosion cracking (NUREG-2192 Section 3.4.2.2.7). Plant-specific operating experience has not revealed any issues related to loss of material due to pitting or crevice corrosion. Therefore, these components are not susceptible to loss of material due to pitting and crevice corrosion (NUREG-2192 Section 3.4.2.2.9).
6. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination. The internally coated Resin Heater Tank meets the six criteria in GALL-SLR AMP XI.M42, Element 4, to use the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program in lieu of the Internal Coatings/Linings for In-Scope Piping, Piping Component, Heat Exchangers, and Tanks (B.2.1.28) program.

Table 3.4.2-2 Condenser Air Removal and Off-Gas System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37419	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
37420	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
38291	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38292	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38294	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38295	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38017	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
38019	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
38018	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
38280	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38020	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38281	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38021	Heat Exchanger – (Offgas SJAIE Inter and After Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38296	Heat Exchanger – (Recombiner Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38297	Heat Exchanger – (Recombiner Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38298	Heat Exchanger – (Recombiner Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D

Table 3.4.2-2 Condenser Air Removal and Off-Gas System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38299	Heat Exchanger – (Recombiner Condenser) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38030	Heat Exchanger – (Recombiner Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
38032	Heat Exchanger – (Recombiner Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
38031	Heat Exchanger – (Recombiner Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
38284	Heat Exchanger – (Recombiner Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38028	Heat Exchanger – (Recombiner Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38285	Heat Exchanger – (Recombiner Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38029	Heat Exchanger – (Recombiner Condenser) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38033	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
39240	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 1
38035	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
38034	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
38036	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
38045	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
38037	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
38039	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-2 Condenser Air Removal and Off-Gas System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38043	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
38041	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B
38040	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
38044	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4.1-081	B
38042	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-73	3.4.1-014	B

Table 3.4.2-2 Condenser Air Removal and Off-Gas System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34518	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
34519	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
39016	Drip Pan	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
39018	Drip Pan	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
39017	Drip Pan	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.E5.A-410	3.3.1-135	C
37581	Flow Device	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37583	Flow Device	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
37582	Flow Device	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
37585	Flow Device	Throttle	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37587	Flow Device	Throttle	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
37586	Flow Device	Throttle	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
37993	Heat Exchanger – (Actuator Package Cooling Skid Heat Exchanger Tubing) Tubes	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VIII.I.SP-6	3.4.1-054	C
37994	Heat Exchanger – (Actuator Package Cooling Skid Heat Exchanger Tubing) Tubes	Leakage Boundary (Spatial)	Copper Alloy with less than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-92	3.4.1-043	C
34806	Heat Exchanger – (Drain Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34808	Heat Exchanger – (Drain Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
34809	Heat Exchanger – (Drain Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34810	Heat Exchanger – (Drain Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
34801	Heat Exchanger – (Drain Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
34803	Heat Exchanger – (Drain Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34802	Heat Exchanger – (Drain Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
34800	Heat Exchanger – (Drain Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
34798	Heat Exchanger – (Drain Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
34797	Heat Exchanger – (Drain Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
34823	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34825	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
34828	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34827	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
34816	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
34818	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34817	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
34813	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
34812	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
34815	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34814	Heat Exchanger – (Feedwater Heaters No. 1 thru 4) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38049	Heat Exchanger – (Feedwater Heaters No. 5) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38048	Heat Exchanger – (Feedwater Heaters No. 5) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38052	Heat Exchanger – (Feedwater Heaters No. 5) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
38051	Heat Exchanger – (Feedwater Heaters No. 5) Tube Sheet	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
39023	Heat Exchanger – (Feedwater Heaters No. 5) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
39025	Heat Exchanger – (Feedwater Heaters No. 5) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
39024	Heat Exchanger – (Feedwater Heaters No. 5) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
39022	Heat Exchanger – (Feedwater Heaters No. 5) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
39021	Heat Exchanger – (Feedwater Heaters No. 5) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
39020	Heat Exchanger – (Feedwater Heaters No. 5) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	D
39019	Heat Exchanger – (Feedwater Heaters No. 5) Tubes	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
34841	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 6
34842	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-92	3.4.1-043	C
37593	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-8	3.4.1-027	C
37594	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-29	3.4.1-033	D

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38972	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 4
34838	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-92	3.4.1-043	C
34836	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 6
37595	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-8	3.4.1-027	C
37596	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-29	3.4.1-033	D
38973	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 4
37597	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-57	3.4.1-028	A
37599	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-78	3.2.1-051	A
37598	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-8	3.4.1-027	C
34834	Heat Exchanger – (Reactor Feedwater Booster Pump Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-92	3.4.1-043	C
38058	Heat Exchanger – (Reactor Feedwater Pump Jacket Water Cooling) Shell Side Components	Heat Transfer	Carbon Steel	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-64	3.4.1-028	C
38057	Heat Exchanger – (Reactor Feedwater Pump Jacket Water Cooling) Shell Side Components	Heat Transfer	Carbon Steel	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.1.2)			H, 3
39086	Heat Exchanger – (Reactor Feedwater Pump Jacket Water Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 5
38056	Heat Exchanger – (Reactor Feedwater Pump Jacket Water Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.S-23	3.4.1-025	A

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38055	Heat Exchanger – (Reactor Feedwater Pump Jacket Water Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
38054	Heat Exchanger – (Reactor Feedwater Pump Jacket Water Cooling) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-77	3.4.1-015	B
34713	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 6
34714	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Shell Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-92	3.4.1-043	C
37600	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-8	3.4.1-027	C
37601	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-29	3.4.1-033	D
38970	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 4
34696	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-92	3.4.1-043	C
34695	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.H.S-454	3.4.1-106	E, 6
37602	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-8	3.4.1-027	C
37603	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-29	3.4.1-033	D
38971	Heat Exchanger – (Reactor Feedwater Pump Oil Cooler) Tube Side Components	Pressure Boundary	Copper Alloy with 15% Zinc or More	Closed Cycle Cooling Water (Internal)	None	None	VII.C2.A-473a	3.3.1-160	I, 4
37609	Heat Exchanger – (Reactor Feedwater Pump Oil Coolers) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-57	3.4.1-028	A
37608	Heat Exchanger – (Reactor Feedwater Pump Oil Coolers) Tubes	Heat Transfer	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-78	3.2.1-051	A
37604	Heat Exchanger – (Reactor Feedwater Pump Oil Coolers) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.E.SP-8	3.4.1-027	C
34692	Heat Exchanger – (Reactor Feedwater Pump Oil Coolers) Tubes	Pressure Boundary	Copper Alloy with less than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-92	3.4.1-043	C

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34520	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37855	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-91	3.4.1-040	A
35024	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D2.S-11	3.4.1-001	A, 1
34522	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34521	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
34523	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-16	3.4.1-005	B
34530	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.D2.SP-118a	3.4.1-002	B
34531	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.SP-127a	3.4.1-003	B
37890	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-95	3.4.1-044	A
34528	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
35026	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
34529	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
34524	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37710	Piping, piping components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-91	3.4.1-040	A
35025	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D2.S-11	3.4.1-001	A, 1
34526	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34525	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34527	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-16	3.4.1-005	B
37612	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.D2.SP-118a	3.4.1-002	B
37613	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.SP-127a	3.4.1-003	B
37615	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
37614	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
37616	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
37793	Pump Casing (Auxiliary Oil Pump for Motor-Driven RFW Pumps)	Pressure Boundary	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37794	Pump Casing (Auxiliary Oil Pump for Motor-Driven RFW Pumps)	Pressure Boundary	Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-91	3.4.1-040	A
34563	Pump Casing (Feedwater Booster Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
34570	Pump Casing (Feedwater Booster Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34571	Pump Casing (Feedwater Booster Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
34559	Pump Casing (Feedwater Pumps)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
34560	Pump Casing (Feedwater Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34561	Pump Casing (Feedwater Pumps)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
34578	Pump Casing (Feedwater Seal Injection Booster Pumps)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.D2.SP-118a	3.4.1-002	B
34579	Pump Casing (Feedwater Seal Injection Booster Pumps)	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.SP-127a	3.4.1-003	B
34575	Pump Casing (Feedwater Seal Injection Booster Pumps)	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34574	Pump Casing (Feedwater Seal Injection Booster Pumps)	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
34591	Pump Casing (Hydrostatic Test Pump)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
34593	Pump Casing (Hydrostatic Test Pump)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34592	Pump Casing (Hydrostatic Test Pump)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
37857	Pump Casing (Turbine-Driven RFW Pump Clutch Hydraulic Actuator Pump)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37858	Pump Casing (Turbine-Driven RFW Pump Clutch Hydraulic Actuator Pump)	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-91	3.4.1-040	A
37889	Strainer (Element)	Filter	Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-95	3.4.1-044	A
37624	Strainer (Element)	Filter	Stainless Steel	Treated Water > 140°F (External)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
37626	Strainer (Element)	Filter	Stainless Steel	Treated Water > 140°F (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
34551	Tanks (Dissolution Column)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
35012	Tanks (Dissolution Column)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34552	Tanks (Dissolution Column)	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-75	3.4.1-012	B
37726	Tanks (Motor-Driven RFW Pump Oil Reservoir)	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37729	Tanks (Motor-Driven RFW Pump Oil Reservoir)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.SP-60	3.4.1-037	A
37792	Tanks (Motor-Driven RFW Pump Oil Reservoir)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-91	3.4.1-040	A

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37852	Tanks (Turbine-Driven RFW Pump Clutch Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37853	Tanks (Turbine-Driven RFW Pump Clutch Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.SP-60	3.4.1-037	A
37854	Tanks (Turbine-Driven RFW Pump Clutch Oil Reservoir)	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-91	3.4.1-040	A
34532	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
39043	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	V.D2.E-10	3.2.1-001	A, 2
34534	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34538	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B
34535	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-16	3.4.1-005	B
34539	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.D2.SP-118a	3.4.1-002	B
34540	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.SP-127a	3.4.1-003	B
34541	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
34542	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B
34543	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
37714	Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.D2.SP-91	3.4.1-040	A
34545	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4.1-081	B
34544	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-73	3.4.1-014	B

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34546	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-16	3.4.1-005	B
37633	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.D2.SP-118a	3.4.1-002	B
37634	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D2.SP-127a	3.4.1-003	B
37636	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-88	3.4.1-011	B
37637	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.D2.SP-87	3.4.1-085	B

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3
2. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.7.
3. Water Chemistry (B.2.1.2) program will be used to manage reduction of heat transfer for carbon steel heat exchanger components in treated water.
4. The reactor and turbine building closed loop cooling water system environments are pure water chemistry-controlled environments where ammonia-forming bacteria growth does not exist and cracking due to bacteria growth is not an applicable aging effect.
5. The reactor and turbine building closed loop cooling water system environments are pure water chemistry-controlled environments and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.

Table 3.4.2-3 Feedwater/High Pressure Coolant Injection System Summary of Aging Management Evaluation

6. The review of 10 years of plant-specific operating experience has not identified cracking in copper alloy with 15% zinc or more in air environments due to potential exposure to ammonia or ammonium compounds. The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking in copper alloy with 15% zinc or more in air due to the potential for exposure to ammonia or ammonium compounds in air. This approach for aging management is similar to that in GALL-SLR for loss of material and cracking in aluminum alloy and stainless steel due to potential exposure to halides in air.

Table 3.4.2-4 Main Generator and Auxiliary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37824	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
37825	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
37832	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	D
37833	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	D
37834	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	D
37835	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Shell Side Components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-80	3.4.1-085	B
38331	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
39087	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
38333	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.A.S-23	3.4.1-025	A
37837	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
39088	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)			H, 1
38171	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VIII.A.S-23	3.4.1-025	A
38326	Heat Exchanger – (Stator Winding Cooling Water System Heat Exchanger) Tube Side Components	Leakage Boundary (Spatial)	Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-072	D

Table 3.4.2-4 Main Generator and Auxiliary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
37803	Piping elements	Leakage Boundary (Spatial)	Glass	Air - Indoor, Uncontrolled (External)	None	None	VIII.I.SP-33	3.4.1-055	A
37804	Piping elements	Leakage Boundary (Spatial)	Glass	Condensation (Internal)	None	None	VIII.I.SP-68	3.4.1-055	A
37805	Piping elements	Leakage Boundary (Spatial)	Glass	Treated Water (Internal)	None	None	VIII.I.SP-35	3.4.1-055	A
37840	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
37841	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B
38166	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
38167	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
37843	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
38325	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Waste Water > 140°F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-721	3.3.1-155	A
38324	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Waste Water > 140°F (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3.1-095	A
37817	Pump Casing (Stator Winding Cooling Water Pumps)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
37818	Pump Casing (Stator Winding Cooling Water Pumps)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B
37826	Pump Casing (Stator Winding Cooling Water Pumps)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
37827	Pump Casing (Stator Winding Cooling Water Pumps)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
38172	Tanks (Cal Gas Humidifier)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
38173	Tanks (Cal Gas Humidifier)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B

Table 3.4.2-4 Main Generator and Auxiliary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
38327	Tanks (Cal Gas Humidifier)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-97	3.4.1-011	B
38212	Tanks (Cal Gas Humidifier)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-162	3.4.1-083	B
37830	Tanks (Stator Water Cooling Demineralizer)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
37831	Tanks (Stator Water Cooling Demineralizer)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B
37828	Tanks (Stator Water Cooling Demineralizer)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-162	3.4.1-083	B
37811	Tanks (Stator Water Cooling Storage Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
37812	Tanks (Stator Water Cooling Storage Tank)	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B
37813	Tanks (Stator Water Cooling Storage Tank)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
37814	Tanks (Stator Water Cooling Storage Tank)	Leakage Boundary (Spatial)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B
37815	Tanks (Stator Water Cooling Storage Tank)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.E.SP-97	3.4.1-011	B
37816	Tanks (Stator Water Cooling Storage Tank)	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.E.SP-162	3.4.1-083	B
37846	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
37847	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B
38170	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
37850	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
37851	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B

Table 3.4.2-4 Main Generator and Auxiliary System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The turbine building closed loop cooling water system environment is a pure water chemistry-controlled environment and includes no additives. As such, there are no corrosion inhibitors and long-term loss of material applies. This aging effect is managed by the One-Time Inspection (B.2.1.20) program.

Table 3.4.2-5 Main Steam System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33410	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
33409	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
33488	Expansion Joints	Pressure Boundary	Nickel Alloy	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.B2.SP-127a	3.4.1-003	B
34990	Expansion Joints	Pressure Boundary	Nickel Alloy	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VII.E3.A-773	3.3.1-244	B
39045	Expansion Joints	Pressure Boundary	Nickel Alloy	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA			F, 2
33487	Expansion Joints	Pressure Boundary	Nickel Alloy	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
34664	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.B2.SP-118a	3.4.1-002	B
34663	Expansion Joints	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.B2.SP-127a	3.4.1-003	B
34666	Expansion Joints	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
39044	Expansion Joints	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 2
34665	Expansion Joints	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
33417	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
35013	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
33414	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
33415	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
35014	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
35007	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4.1-081	B

Table 3.4.2-5 Main Steam System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33491	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
34991	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.B2.SP-118a	3.4.1-002	B
34992	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.B2.SP-127a	3.4.1-003	B
34993	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.B2.SP-98	3.4.1-011	B
35017	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
34994	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
36474	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
36472	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
36473	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
33418	Piping, piping components	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
35015	Piping, piping components	Pressure Boundary	Carbon Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
33419	Piping, piping components	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
33420	Piping, piping components	Pressure Boundary	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
35008	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4.1-081	B
34670	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
35016	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
35009	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4.1-081	B
34669	Piping, piping components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B

Table 3.4.2-5 Main Steam System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34661	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.B2.SP-118a	3.4.1-002	B
33421	Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.B2.SP-127a	3.4.1-003	B
34885	Piping, piping components	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.B2.SP-98	3.4.1-011	B
35018	Piping, piping components	Pressure Boundary	Stainless Steel	Steam (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
34884	Piping, piping components	Pressure Boundary	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
34668	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
35019	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cumulative Fatigue Damage	TLAA	VII.E4.A-62	3.3.1-002	A, 1
34667	Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
33437	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
33438	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
33439	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
35010	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4.1-081	B
34671	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
34677	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.B2.SP-118a	3.4.1-002	B
34676	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.B2.SP-127a	3.4.1-003	B
34679	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.B2.SP-98	3.4.1-011	B
34678	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
36477	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B

Table 3.4.2-5 Main Steam System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36476	Valve Body	Leakage Boundary (Spatial)	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B
33442	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
33443	Valve Body	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-160	3.4.1-014	B
34674	Valve Body	Pressure Boundary	Carbon Steel	Steam (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4.1-005	B
35011	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4.1-081	B
34675	Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
34681	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.B2.SP-118a	3.4.1-002	B
34680	Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.B2.SP-127a	3.4.1-003	B
34887	Valve Body	Pressure Boundary	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.B2.SP-98	3.4.1-011	B
34886	Valve Body	Pressure Boundary	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-155	3.4.1-084	B
34683	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Cracking	Water Chemistry (B.2.1.2)	VIII.C.SP-88	3.4.1-011	B
34682	Valve Body	Pressure Boundary	Stainless Steel	Treated Water > 140°F (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.C.SP-87	3.4.1-085	B

Table 3.4.2-5 Main Steam System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3
2. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.6.

Table 3.4.2-6 Main Turbine and Auxiliary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33851	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4.1-009	B
33854	Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4.1-006	B
33831	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
33832	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.A.SP-91	3.4.1-040	A
39052	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B2.S-08	3.4.1-001	A, 1
33835	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4.1-081	B
33833	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
38301	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Wall Thinning/Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.E.S-16	3.4.1-005	B
38203	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38204	Piping, piping components	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
33837	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Cracking	One-Time Inspection (B.2.1.20)	VIII.A.SP-118a	3.4.1-002	B
33836	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.SP-127a	3.4.1-003	B
33838	Piping, piping components	Leakage Boundary (Spatial)	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.A.SP-95	3.4.1-044	A
33999	Tanks (Lube Oil Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
34000	Tanks (Lube Oil Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.SP-60	3.4.1-037	A

Table 3.4.2-6 Main Turbine and Auxiliary System Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34001	Tanks (Lube Oil Storage Tank)	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.A.SP-91	3.4.1-040	A
38207	Tanks (Waste Oil Receiver)	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
38293	Tanks (Waste Oil Receiver)	Leakage Boundary (Spatial)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.SP-60	3.4.1-037	A
38208	Tanks (Waste Oil Receiver)	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38209	Tanks (Waste Oil Receiver)	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
33839	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
33840	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.25)	VIII.A.SP-91	3.4.1-040	A
33843	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4.1-081	B
33841	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.B2.SP-73	3.4.1-014	B
38205	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3.1-193	B
38206	Valve Body	Leakage Boundary (Spatial)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3.1-091	A
33847	Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-034	A
33848	Valve Body	Pressure Boundary	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.1.2)	VIII.A.SP-71	3.4.1-014	B

Table 3.4.2-6 Main Turbine and Auxiliary System Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

3.5 AGING MANAGEMENT OF STRUCTURES AND COMPONENT SUPPORTS

3.5.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.4, Scoping and Screening Results: Structures, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Component Supports Commodity (2.4.1)
- Primary Containment (2.4.2)
- Reactor Building (2.4.3)
- Screen and Pump House Building (2.4.4)
- Structural Commodity Group (2.4.5)
- Turbine, Waste Handling, and Admin. Structures (2.4.6)
- Yard Structures (2.4.7)

3.5.2 RESULTS

The following tables summarize the results of the aging management review for Structures and Component Supports.

Table 3.5.2-1 Component Supports Commodity - Summary of Aging Management Evaluation

Table 3.5.2-2 Primary Containment - Summary of Aging Management Evaluation

Table 3.5.2-3 Reactor Building - Summary of Aging Management Evaluation

Table 3.5.2-4 Screen and Pump House Building - Summary of Aging Management Evaluation

Table 3.5.2-5 Structural Commodity Group - Summary of Aging Management Evaluation

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures - Summary of Aging Management Evaluation

Table 3.5.2-7 Yard Structures - Summary of Aging Management Evaluation

3.5.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.5.2.1.1 Component Supports Commodity

Materials

The materials of construction for the Component Supports Commodity components are:

- Carbon Steel

- Carbon and Low Alloy Steel Bolting
- High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Lubrite
- Reinforced concrete
- Stainless Steel
- Stainless Steel Bolting

Environments

The Component Supports Commodity components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Component Supports Commodity components require management:

- Cracking
- Loss of Material
- Loss of Mechanical Function
- Loss of Preload
- Reduction in Concrete Anchor Capacity
- Reduction in Fracture Toughness

Aging Management Programs

The following aging management programs manage the aging effects for the Component Supports Commodity components:

- ASME Section XI, Subsection IWF (B.2.1.30)
- Structures Monitoring (B.2.1.33)
- Water Chemistry (B.2.1.2)

3.5.2.1.2 Primary Containment

Materials

The materials of construction for the Primary Containment components are:

- Aluminum

- Carbon Steel
- Carbon Steel; dissimilar metal welds
- Carbon and Low Alloy Steel Bolting
- Coatings
- Elastomers
- Galvanized Bolting
- Lubrite
- Reinforced concrete
- Stainless Steel
- Stainless Steel Bolting

Environments

The Primary Containment components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Concrete
- Treated Water

Aging Effect Requiring Management

The following aging effects associated with the Primary Containment components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Cracking, Loss of Material
- Cumulative Fatigue Damage
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Loss of Coating or Lining Integrity
- Loss of Leak tightness
- Loss of Material
- Loss of Mechanical Function
- Loss of Preload
- Loss of Sealing
- Reduction of Strength; Loss of Mechanical Properties

Aging Management Programs

The following aging management programs manage the aging effects for the Primary Containment components:

- 10 CFR Part 50, Appendix J (B.2.1.31)
- ASME Section XI, Subsection IWE (B.2.1.29)
- One-Time Inspection (B.2.1.20)
- Protective Coating Monitoring and Maintenance (B.2.1.35)
- Structures Monitoring (B.2.1.33)
- TLAA

3.5.2.1.3 Reactor Building

Materials

The materials of construction for the Reactor Building components are:

- Aluminum
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete
- Concrete Block
- Reinforced concrete
- Stainless Steel
- Stainless Steel Bolting

Environments

The Reactor Building components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Treated Water
- Water - Flowing

Aging Effect Requiring Management

The following aging effects associated with the Reactor Building components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Cracking, Loss of Material
- Cumulative Fatigue Damage
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Building components:

- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)
- TLAA
- Water Chemistry (B.2.1.2)

3.5.2.1.4 Screen and Pump House Building

Materials

The materials of construction for the Screen and Pump House Building components are:

- Aluminum
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Cast Iron
- Concrete Block
- Galvanized Bolting
- Reinforced concrete
- Stainless Steel
- Stainless Steel Bolting

Environments

The Screen and Pump House Building components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Raw Water
- Water - Flowing

Aging Effect Requiring Management

The following aging effects associated with the Screen and Pump House Building components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Cracking, Loss of Material
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Screen and Pump House Building components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)
- Masonry Walls (B.2.1.32)
- Selective Leaching (B.2.1.21)
- Structures Monitoring (B.2.1.33)

3.5.2.1.5 Structural Commodity Group

Materials

The materials of construction for the Structural Commodity Group components are:

- Aluminum
- Asbestos
- Calcium Silicate
- Carbon Steel

- Carbon and Low Alloy Steel Bolting
- Elastomers
- Fiberglass
- Galvanized Steel
- Stainless Steel
- Stainless Steel (Mirror Insulation)
- Stainless Steel Bolting

Environments

The Structural Commodity Group components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor

Aging Effect Requiring Management

The following aging effects associated with the Structural Commodity Group components require management:

- Cracking, Loss of Material
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Reduced Thermal Insulation Resistance

Aging Management Programs

The following aging management programs manage the aging effects for the Structural Commodity Group components:

- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- One-Time Inspection (B.2.1.20)
- Structures Monitoring (B.2.1.33)

3.5.2.1.6 Turbine, Waste Handling, and Admin. Structures

Materials

The materials of construction for the Turbine, Waste Handling, and Admin. Structures components are:

- Aluminum

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Concrete Block
- Galvanized Steel
- Reinforced concrete

Environments

The Turbine, Waste Handling, and Admin. Structures components are exposed to the following environments:

- Air - Indoor, Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effect Requiring Management

The following aging effects associated with the Turbine, Waste Handling, and Admin. Structures components require management:

- Cracking
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Cracking, Loss of Material
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine, Waste Handling, and Admin. Structures components:

- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)

3.5.2.1.7 Yard Structures

Materials

The materials of construction for the Yard Structures components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Galvanized Bolting
- Galvanized Steel
- Reinforced concrete
- Soil, rip-rap, gravel, rock
- Stainless Steel Bolting

Environments

The Yard Structures components are exposed to the following environments:

- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effect Requiring Management

The following aging effects associated with the Yard Structures components require management:

- Cracking
- Cracking and Distortion
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Loss of Strength
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Material; Loss of Form
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Yard Structures components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)
- Structures Monitoring (B.2.1.33)

3.5.2.2 **AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report**

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Structures and Component Supports, those programs are addressed in the following subsections.

3.5.2.2.1 **Pressurized Water Reactor and Boiling Water Reactor Containments**

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 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.

Table 3.5.1 Item Numbers 3.5.1-001 and 3.5.1-002 are not applicable to the Nine Mile Point Nuclear Station, Unit 1 (NMP1) Mark I steel containment. The Primary Containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building and is mounted on support structures that transmit loads to the concrete foundation of the Reactor Building as shown in UFSAR Figures III-10 and V-3. As such, Primary Containment internal concrete is not exposed to groundwater/soil environments and cannot settle independently of the Reactor Building foundation. The Reactor Building foundation design does not utilize porous concrete in a subfoundation and the NMP1 CLB does not credit a dewatering system to control building settlement. Lastly, NMP1 does not have an ASME Section XI, Subsection IWL program.

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 (TN249) and ASME Code Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3440 of ASME Code Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects for portions of the concrete containment components that exceed specified temperature limits (i.e., general area temperature greater than 66 degree Celsius [°C] or 150 degree Fahrenheit [°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. Acceptance criteria are described in BTP RLSB-1, “Aging Management Review – Generic, July 2017” (Appendix Section A.1 of this SRP-SLR).

Item Number 3.5.1-003 is not applicable to the NMP1 Mark I steel containment. This Item Number is for concrete containment components. However, the temperature criteria in this section applies to all concrete within primary containment. NMP1 UFSAR Section VI E.1.2 limits the bulk air temperature inside the drywell during normal plant operation to 150 degrees F. The drywell is cooled during normal power operation by a closed loop ventilation system designed to hold the average temperature to 150 degrees F or lower. The primary containment ventilation system is described in UFSAR Section VI E.1.0 and in SLRA Section 2.3.3.4 Containment Systems. Plant operating experience has not identified elevated general area and local area temperatures as a concern for concrete structural components. Therefore, concrete structural components located inside the drywell are not subject to general area temperatures greater than 150 degrees F, or local area concrete temperature greater than 200 degrees F.

The potential for gamma radiation induced heating in the sacrificial shield wall is addressed in EPRI Report 3002002676, Revision 0, February 2014, “Expected Condition of Reactor Cavity Concrete After 80 Years of Radiation Exposure,” which concludes that the gamma dose for BWR plants will be no higher than the gamma dose for PWR plants. EPRI Report 3002008129, Revision 0, December 2016, “Long-Term Operations: Impact of Radiation Heating on PWR Biological Shield Concrete” evaluates the impact of radiation induced heating on bounding PWR plants. The evaluation determined that the localized temperature rise in the shield wall resulted in a localized concrete temperature of less than 180 degrees F. Therefore, this report also indicates that the localized temperatures in the NMP1 reactor shield wall are less than 200 degrees F. Note that the configuration of the NMP1 reactor shield wall, which is described in UFSAR Section XII B.1.2.1, reflects the configuration shown in EPRI Report 3002002676, Figure 7-6, for the wall described as a biological shield in the figure.

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 (ASME 2008-TN8166), and 10 CFR Part 50 (TN249), Appendix J AMPs, to manage this aging effect. Further evaluation of plant-specific programs is recommended to manage this aging effect if corrosion is indicated from the IWE examinations. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR)*

Table 3.5.1 Item Numbers 3.5.1-004 and 3.5.1-005 are not applicable to the NMP1 Mark I steel containment. These item numbers only apply to BWR Mark I concrete containments in addition to BWR Mark II, BWR Mark III, and PWR containments. However, Item Number 3.5.1-035 is applicable to NMP1. The ASME Section XI, Subsection IWE (B.2.1.29) program and the 10 CFR Part 50, Appendix J (B.2.1.31) program will be used to manage the loss of material for carbon steel and dissimilar metal welds in accessible and inaccessible areas of drywell steel elements (shell,

head, embedded and sandpocket regions) and penetrations (containment sleeves, drywell electrical, drywell mechanical—including flued heads and bellows, and torus mechanical) exposed to air – indoor in the Primary Containment.

The NMP1 Primary Containment design includes an accessible moisture barrier in the drywell basement at the junction of the concrete floor and drywell shell. This barrier is a caulk-like material applied at the interface that prevents moisture intrusion into the inaccessible region between the shell and concrete basement floor. General visual inspections are performed of the accessible moisture barriers for wear, damage, erosion, tears, cracks, or other defects that may violate the leak-tight integrity. The moisture barrier inspections are performed as part of the ASME Section XI, Subsection IWE (B.2.1.29) program. The examination of moisture barriers is intended to identify conditions which may allow intrusion of moisture into inaccessible areas of the pressure-retaining metal drywell shell. Signs of degradation of the moisture barrier are entered into the corrective action program, evaluated, and repaired as required by engineering evaluations.

The NMP1 Primary Containment design features a 2-inch inaccessible air gap between the steel drywell shell and the surrounding concrete. To manage potential leakage into this gap, the design incorporates two drainage paths. The reactor cavity shelf is designed to capture leakage that passes through the drywell refueling seal bellows. The shelf is sloped away from the air gap towards a shelf drain. Alternatively, ten 4-inch diameter pipes drain potential leakage from the top of the sandpocket into the torus room. These sandpocket drain lines are inspected during each refueling outage, and no signs of leakage have been observed. Boroscopic inspections performed in 1988 and 2006 found the drain lines to be unobstructed. To provide reasonable assurance that moisture is not present in the air gap region of the steel drywell, boroscopic inspections of the drain lines have been scheduled to identify moisture and confirm the absence of blockages on a ten-year frequency in the subsequent period of extended operation.

For NMP1, no additional plant-specific activities are warranted beyond those described above and those that are currently established as part of the ASME Section XI, Subsection IWE (B.2.1.29) program. The continued monitoring of the drywell shell in accordance with the ASME Section XI, Subsection IWE (B.2.1.29) program, and the testing conducted in accordance with the 10 CFR Part 50, Appendix J (B.2.1.31) program provide reasonable assurance that the loss of material due to corrosion of steel elements of the containment will be detected prior to a loss of intended function. These activities and programs provide assurance that the drywell shell will remain capable of performing its design function through the subsequent period of extended operation.

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 Section A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-006 evaluates loss of material due to general, pitting, and crevice corrosion in steel torus shell of the NMP1 Mark I containment exposed to

air-indoor and treated water environments. The ASME Section XI, Subsection IWE (B.2.1.29) program and the 10 CFR Part 50, Appendix J (B.2.1.31) program will be used to manage the loss of material of carbon steel elements in the torus shell as well as the vent system lines, header, deflector, and bellows. These surface areas are required to be 100 percent visually examined in the current ISI Interval.

The NMP1 torus is constructed of A201 Grade B steel plates with a certified minimum thickness of 0.460 inches. This value included an original corrosion allowance of 0.0625 inches, which was added to the minimum wall thickness. However, subsequent addition of hydrodynamic loads resulting from a loss of coolant accident (LOCA) and safety relief valve (SRV) actuation to the containment design bases resulted in a reduction of corrosion allowance. To establish reasonable assurance that the revised minimum wall thickness is not reached, NMP1 established a torus corrosion monitoring program to monitor torus wall thickness and corrosion rate. Determination of torus corrosion rates is an ongoing activity that considers inspection results and the remaining corrosion allowance. The torus corrosion monitoring program was developed to monitor the torus shell material thickness, and the station specific inspection program is included in the ASME Section XI, Subsection IWE (B.2.1.29) program.

The torus corrosion monitoring program manages corrosion of the torus through inspection and analysis. The program uses ultrasonic measurements, material coupon analysis and visual inspections. Ultrasonic measurements are performed on predetermined locations to determine torus shell thickness and corrosion rate. Material coupons are stored partially submerged at the waterline of the torus and are periodically removed to obtain a corrosion rate. Visual inspections of the exterior of the torus are performed to detect external corrosion and any visible deficiency of the support structure. Issue reports are required to be initiated and dispositioned in accordance with the corrective action process. Issue reports are required if any ultrasonic measurement is below the minimum wall thickness, if the measured corrosion rate indicates minimum wall thickness will be reached within four refueling cycles or as required for observed visible deficiencies.

During a 2019 IWE visual inspection of the torus interior, inspectors identified a corrosion pattern known as “tigerstriping” along the sidewalls below the waterline. This pattern, characterized by alternating black oxide ridges and bare metal valleys, exhibited localized pitting that exceeded the IWE acceptance criterion of 10 percent wall loss in certain areas. An engineering evaluation determined that, despite the visual severity, the pit depths remained within allowable limits, and the torus was deemed acceptable for continued service. To validate structural integrity and fulfill follow-up requirements, an ANII-approved ultrasonic thickness sampling plan was performed during the 2023 refueling outage. The results confirmed torus structural integrity with the ASME Code required 95 percent confidence level, and projections indicate that minimum wall thickness thresholds will not be reached until after the end of the subsequent period of extended operation.

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 of plant-specific programs is recommended to manage this aging effect if corrosion is significant. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

Table 3.5.1 Item Numbers 3.5.1-006 and 3.5.1-007 evaluate loss of material due to general, pitting, and crevice corrosion in steel torus ring girder, downcomers, and torus mechanical penetrations of the NMP1 Mark I containment exposed to air – indoor and treated water environments. The ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage the loss of material of carbon steel torus ring girders, downcomers, and submerged mechanical penetrations of the torus.

The last inspection of the ring girders was performed in 2023, inspections found minor surface corrosion with no apparent base metal lost. Inspections of the downcomers identified flaking coatings and rust bleed through above the water line. While performing inspections of the submerged portions of the downcomers in 2019 divers found random pitting where up to 25 percent of the base metal was lost. The issue was entered into the corrective action program and evaluated. Structural engineering reviewed the design calculation and determined that the material loss was acceptable. The next inspections of the submerged portions of the downcomers are scheduled to be performed in 2029. Any deficiencies identified on future inspections will be documented and addressed in accordance with the corrective action program.

Penetrations of the NMP1 Mark I containment are subject to periodic examinations to detect loss of material due to general, pitting, and crevice corrosion. There has been no plant-specific OE associated with these component types that has identified significant loss of material due crevice corrosion as a result of exposure to air – indoor and treated water.

The ASME Section XI, Subsection IWE (B.2.1.29) program will manage loss of material due to corrosion of the steel torus ring girders, downcomers, and torus mechanical penetrations during the subsequent period of extended operation, a plant-specific aging management program is not required.

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 TLAA as defined in 10 CFR 54.3 (TN4878). The 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.

Table 3.5.1 Item Number 3.5.1-008 is not applicable to the NMP1 Mark I steel containment. The item number is applicable only to PWR and BWR prestressed concrete containments.

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, 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 TLAAAs as defined in 10 CFR 54.3. The TLAAAs 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 TLAAAs.

For the above-stated containment pressure-retaining components (corresponding to Table 3.5-1, Items 027 and 040) subject to cyclic loading for which no CLB fatigue analysis exists at the time of an SLRA submittal, a plant-specific further evaluation may be performed to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for the component. As one acceptable approach, the aging effect does not require aging management actions if the further evaluation demonstrates that the six criteria for cyclic loading in paragraph NE-3222.4(d) (NE-3221.5[d] in 1980 and later code editions), "Analysis for Cyclic Operation, Vessels Not Requiring Analysis for Cyclic Service," of ASME Code, Section III, Division 1 (1974 edition or later edition incorporated by reference in 10 CFR 50.55a[a][i]), that provide for a waiver from detailed fatigue analysis are satisfied for applicable component materials through the end of the subsequent period of extended operation. The option to perform a fatigue waiver analysis to address the aging effect of cracking due to cyclic loading, for specific containment metallic components, is in lieu of performing supplemental surface examinations or performing or crediting an appropriate 10 CFR Part 50, Appendix J, leak-rate test discussed in GALL-SLR Report AMP XI.S1, "ASME Section XI, Subsection IWE."

Table 3.5.1 Item Number 3.5.1-009 evaluates cumulative fatigue damage due to cyclic loading (only for an existing analysis that is part of the CLB) for steel elements of Mark I steel containments (including torus, vent line, vent header, vent line bellows, vent line deflector, and downcomers) drywell shell, metal plate, equipment hatch, and drywell mechanical and electrical penetrations common to all BWR containment designs that are exposed to air – indoor environments. Components of the NMP1 Primary Containment that were analyzed for fatigue and evaluated as TLAAAs for the SPEO are addressed in SLRA Section 4.6.

NUREG-2191, Section X1.S1, ASME Section XI, Subsection IWE notes that Appendix J leak rate tests capable of detection of cracking may be performed or credited in lieu of the supplemental surface examination.

The 1965 edition of the ASME Section III B&PV Code did not require fatigue analysis of Class B vessels. The drywell penetrations were considered an extension of the drywell and thus did not require fatigue analysis. Fatigue of torus penetrations was addressed in the same analysis as the torus-attached piping, the "Plant Unique Analysis Report of the

Torus Attached Piping for Nine Mile Point Unit 1 Nuclear Generation Station," which was transmitted to the NRC in a letter dated May 22, 1984.

As noted in NUREG-2192, Section 3.5.2.2.1.5, a plant-specific further evaluation may be performed to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for containment pressure-retaining components.

As part of license renewal activities, a fatigue waiver analysis was performed demonstrating that if the NMP1 drywell shell (including metal plate, airlock, equipment hatch, and portions of drywell penetrations (mechanical and electrical)) had been designed to the ASME Code, Section III, Division 1 (1974 Edition with Addenda through Winter 1976) with an expectation to operate for 80 years, it would have met the criteria for fatigue exemption specified by Subsection NE-3222.4(d) "Vessel Not Requiring Analysis for Cyclic Operation." The criteria that were met for the fatigue waiver included: 1) atmospheric to operating pressure cycle, 2) normal operation pressure fluctuation, 3) temperature difference – startup and shutdown, 4) temperature difference – normal operation, 5) temperature difference – dissimilar metals, and 6) mechanical loads. The analysis concluded that the drywell shell (including metal plate, airlock, equipment hatch, and portions of drywell penetrations (mechanical and electrical)) are subjected to a small and acceptable amount of fatigue such that detailed fatigue analysis is not required. The analysis used 80-year projections for cycle counts. As such, cracking due to cyclic loading is not an aging effect requiring management for the drywell shell (including metal plate, airlock, equipment hatch, and portions of drywell penetrations (mechanical and electrical)).

The fatigue waiver analysis did not include portions of high temperature drywell mechanical penetrations tabulated in Table 3.5.2.2.1.5-1 below. As summarized in Table 3.5-1 Item Number 3.5.1-027, cracking due to cyclic loading for portions of high-temperature piping penetrations that are not pressurized during local leak rate testing and do not have a CLB fatigue analysis will be managed by the ASME Subsection XI, Subsection IWE (B.2.1.29) program, including an enhancement to inspect a sample of accessible portions for cracking, and 10 CFR Part 50, Appendix J (B.2.1.31) program, respectively, during the SPEO.

Table 3.5.1 Item Number 3.5.1-040 is not applicable to the NMP1 Mark I steel containment. This item number is applicable only to BWR Mark II containments.

Fatigue Waiver Analysis for the Nine Mile Point Nuclear Station, Unit 1 Drywell

1.0 Introduction

1.1 For drywell components that do not have a fatigue analysis performed per the original plant design specifications and construction codes, Nine Mile Point, Unit 1 (NMP1) has performed an evaluation to show that the drywell would have met the criteria for a fatigue waiver. This evaluation consists of a fatigue waiver analysis based on transient cycle limits (as described in NUREG-2191, Section X.M1), and is a technically acceptable approach to analytically address the effects of cyclic loading (fatigue aging effects) for containment metallic pressure-retaining boundary components.

2.0 Summary

- 2.1 The NMP1 drywell structure, penetrations, and associated components were determined not to have an existing CLB fatigue analysis and therefore have no fatigue TLAAs. These component types include the drywell shell, drywell head, drywell personnel airlock, drywell equipment hatches, drywell electrical penetrations, and drywell mechanical penetrations.

The NMP1 drywell was designed as a Class B vessel in accordance with Section III of the ASME Boiler and Pressure Vessel (B&PV) Code, 1965 edition. The 1965 edition of the ASME Section III B&PV Code did not require fatigue analysis of Class B vessels. As part of SLRA development, NMP1 has documented a fatigue waiver analysis for the SPEO to demonstrate that if the drywell, including mechanical and electrical penetrations, had been designed to the 1974 Edition of ASME Section III, then it would have met the six criteria in NE-3222.4(d) "Vessel Not Requiring Analysis for Cyclic Operation." Methodology, temperature-dependent material properties, and alternating stress intensity values used in this analysis are based on the 1974 Code edition with Addenda through Winter 1976.

The analysis justifies that the drywell and the portions of its penetrations within the scope of the evaluation (summarized below) meet the fatigue waiver criteria specified in NE-3222.4(d) of Section III of the ASME Code and can be considered exempt from detailed fatigue analysis. The six criteria address the following design inputs:

- (1) Atmospheric-to-operating pressure cycles,
 - (2) Normal operation pressure fluctuations,
 - (3) Temperature difference – startup and shutdown,
 - (4) Temperature difference – normal operation,
 - (5) Temperature difference – dissimilar materials, and
 - (6) Mechanical loads.
- 2.2 This analysis excludes any portions of penetrations that are affected by process fluid to the extent that either (a) temperature exceeds the maximum containment temperature of 310°F, and/or (b) temperature difference between adjacent points has a range greater than 278°F.
- 2.3 This analysis does not include stagnant penetrations such as instrumentation and leak off lines, which are expected to be below 310°F and never experience temperature difference range between adjacent points greater than 278°F. This is because the fluid at these containment penetrations experience stagnant no-flow conditions. Cyclic loading is not expected at these locations due to lack of thermal-hydraulic transients caused by pressure or thermally induced loads.
- 2.4 Due to the scope restrictions on maximum temperature and maximum range of temperature difference (see Section 2.2), portions of the following penetrations are

excluded from this evaluation (all other penetrations are fully addressed by this evaluation).

Table 3.5.2.2.1.5-1 Penetrations Excluded from Fatigue Waiver Analysis

Service	Penetration Number
Main Steam	X-2A, X-2B
Emergency Condenser Steam Supply	X-3A, X-3B
Primary Feedwater	X-4A, X-4B
Emergency Condenser Return	X-5A, X-5B
Shutdown Cooling Return	X-7
Shutdown Cooling Supply	X-8
Cleanup Supply	X-9
Core Spray	X-13A, X-14

- 2.5 The drywell penetration configuration for penetrations with hot process pipe, is as shown in UFSAR Figure VI-4. Based on this configuration within the penetration assembly, the drywell penetration sleeve (including bellows) is remote from the process piping and is expected to be at or below 310°F. As a result, this portion of a penetration with hot process pipe is covered by this analysis.
- 2.6 If a safety system penetration is isolated from reactor coolant by means of check valves, the penetration at the containment boundary is in scope for this evaluation.
- 2.7 The materials used in this evaluation to represent the NMP1 drywell shell and its penetrations are conservatively ASTM A201 Grade B (plate) and ASTM A333 Grade 1 (pipe), all of which are carbon steel (CS). In addition, the bellows contain stainless steel (SS) portions made of ASTM A240 Type 321. The analysis is simplified to perform an evaluation of the six criteria on a material basis instead of on an individual penetration basis.
- 2.8 Conservative, bounding number of cycles for 80 years were used with specific values as follows, with further explanations provided in subsequent sections:
- Number of full pressure cycles: 500 (see Section 3.1)
 - Number of significant pressure fluctuations: 25 (see Section 3.2)
 - Number of startup/shutdown cycles: 300 (see Section 3.3)
 - Number of significant temperature fluctuations: 5,000 (see Section 3.4)
 - Number of significant load fluctuations: 10,000 (see Section 3.6)

3.0 Evaluation

The six subsections below present (paraphrased) each of the six criteria for a fatigue waiver specified in the ASME Code for Class MC components and a summary of the

associated analysis performed for the drywell and the portions of its penetrations within the scope of the evaluation.

The following nomenclature is used:

3.1 Atmospheric-to-operating pressure cycles:

α_{inst} = instantaneous coefficient of thermal expansion at T_{ave}

α_1 = α_{inst} for material 1 of a material discontinuity

α_2 = α_{inst} for material 2 of a material discontinuity

dT = temperature difference

E = elastic modulus at T_{ave}

E_1 = E for material 1 of a material discontinuity

E_2 = E for material 2 of a material discontinuity

P = pressure

S_a = alternating stress intensity on applicable fatigue curve at specified number of cycles

S_m = design stress intensity

S = alternating stress intensity at 10^6 cycles

T = temperature

T_{ave} = average temperature for either adjacent points or two materials, as applicable

The number of pressure cycles over the full range from zero to normal operating pressure (1.5 psig) is 500, which is appropriate since it is reasonable to expect the drywell to be pressurized in most cases when the reactor is pressurized. The allowable cycle counts for RPV startup is 240. All other transients that cause pressure cycles on the drywell components occur during upset, emergency, or faulted events. Additionally, the unit is not expected to experience more than 25 Integrated Leak Rate Tests (ILRTs) during the 80-year life. No other transients during normal operations will elevate drywell pressure to 1.5 psig or greater. S_m is the allowable stress intensity value at a given temperature from ASME Section III, Appendix I, Tables I-1.1 and I-1.2. S_a corresponds to the allowable amplitude of the alternating stress component and is plotted against the number of cycles on the fatigue curves found in ASME Section III, Appendix I, Figures I-9.1 and I-9.2.

At 500 cycles and S_m values taken at 310°F, the resulting fatigue curve cycles at $3S_m$ are as follows:

- ASTM A201 Grade B (S_m = 18.8 ksi) = 3,500 cycles
- ASTM A333 Grade 1 (S_m = 17.7 ksi) = 4,000 cycles

- ASTM A240 Type 321 ($S_m = 20.0$ ksi) = 9,950 cycles

Therefore, resulting cycles based on the fatigue curve for each material is greater than the expected 500 operating pressure cycles for 80 years and the criterion is met.

3.2 Normal operation pressure fluctuations

- Operating pressure range = 1.5 psi
- Design pressure range = 62 psi

At 10^6 cycles, $S_a = 12.5$ ksi for CS.

Therefore, for ASTM A201 Grade B, significant pressure fluctuations are those for which the excursion exceeds the quantity:

- $0.062 \times 12.5 (3 \times 18.8) = 0.014$ ksi

For ASTM A333 Grade 1, $S_m = 17.7$ ksi.

Therefore, for ASTM A333 Grade 1, significant pressure fluctuations are those for which the excursion exceeds the quantity:

- $0.062 \times 12.5 \div (3 \times 17.7) = 0.015$ ksi

At 10^6 cycles, $S_a = 26$ ksi for SS.

For ASTM A240 Type 321, $S_m = 20.0$ ksi.

Therefore, for ASTM A240 Type 321, significant pressure fluctuations are those for which the excursion exceeds the quantity:

- $0.062 \times 26 \div (3 \times 20.0) = 0.027$ ksi

These pressure values define what is a significant pressure fluctuation.

The number of significant pressure fluctuations during normal operation is assumed to be 25. This value is conservative given that design basis accidents (DBAs) are very rare events and ILRTs (which pressurize the containment and its associated penetrations to 35 psig) are only required every 10 years. The last ILRT at NMP1 was in 2023, there have been a total of 13 ILRTs performed on NMP1.

At 25 pressure fluctuations; from ASME Section III, Appendix I, Figure I-9.1, the corresponding S_a for CS is 380 ksi (which includes ASTM A201 and ASTM A333).

At 25 pressure fluctuations; from ASME Section III, Appendix I, Figure I-9.2, the corresponding S_a for SS is 425 ksi (which includes ASTM A240 Type 321).

The resulting limit on the normal operation pressure range:

- For ASTM A201 Grade B: $0.062 \times 380 \div (3 \times 18.8) = 0.418$ ksi

- For ASTM A333 Grade 1: $0.062 \times 380 \div (3 \times 17.7) = 0.444$ ksi
- For ASTM A240 Type 321: $0.062 \times 425 \div (3 \times 20.0) = 0.439$ ksi

These values are significantly greater than the normal operation pressure fluctuation range of 1.5 psig and the periodic ILRT pressure of 35 psig; as a result, the normal operation pressure fluctuation meets the requirements of criterion (2).

3.3 Temperature difference – startup and shutdown:

The allowable heatup cycles for NMP1 is 240, therefore 300 cycles will be used below. The drywell and penetrations experience the maximum temperature difference between any two adjacent points occurring during Startup and Shutdowns. The containment and its penetrations are not expected to undergo startup and shutdown cycles in excess of those that are experienced by the RPV. Additionally, this evaluation excludes portions of penetrations that are affected by high temperature process fluid.

- Maximum defined temperature for the vessel steel is 310°F.
- The maximum operating temperature is assumed to be 150°F.
- The minimum defined temperature is assumed to be 32°F.

Normal operating average T: $(150 + 115) \div 2 = 132.5^\circ\text{F}$. Parameter values at T_{ave} from ASME Section III, Appendix I, Tables I-5.0 and I-6.0:

- α_{inst} (CS) = $6.35\text{E-}06$ in/in/°F
- α_{inst} (SS) = $9.30\text{E-}06$ in/in/°F
- E (CS) = 27,804 ksi
- E (SS) = 28,012 ksi

At 300 cycles; from ASME Section III, Appendix I, Figure I-9.1, $S_a = 140$ ksi (CS). Therefore, for the CS components, the limit on the temperature difference is:

- $110 \div (2 \times 27,804 \times 6.35\text{E-}06) = 396^\circ\text{F}$.

At 300 cycles: from ASME Section III, Appendix I, Figure I-9.2, $S_a = 160$ ksi (SS). Therefore, for the SS components, the limit on the temperature difference is:

- $160 \div (2 \times 28,012 \times 9.30\text{E-}06) = 307^\circ\text{F}$

These temperature limits are both greater than the 278°F temperature difference during startup and shutdown, which is assumed to be the difference between the maximum defined temperature (310°F) and the minimum defined temperature (32°F).

These results indicate that the containment could experience shutdown and startup temperature differences (between any two adjacent points) of 396°F (CS) and 307°F (SS), 300 times over 80 years without exceeding the NE-3222.4(d)(3) threshold.

3.4 Temperature difference – normal operation:

It is assumed that the temperature fluctuation between any two adjacent points during normal operation equals the difference between the maximum operating temperature (150°F) and the minimum defined temperature (32°F) for a temperature differential of 118°F. Parameter values at T_{ave} from ASME Section III, Appendix I, Tables I-5.0 and I-6.0:

- $\alpha_{inst} (CS) = 6.35 \text{ E-06 in/in/}^{\circ}\text{F}$
- $\alpha_{inst} (SS) = 9.30 \text{ E-06 in/in/}^{\circ}\text{F}$
- $E (CS) = 27,804 \text{ ksi}$
- $E (SS) = 28,012 \text{ ksi}$

At 10^6 cycles, $S_a = 12.5 \text{ ksi}$ for CS.

Therefore, significant temperature fluctuations for CS are those for which the total algebraic range exceeds the quantity:

- $12.5 \div (27,804 \times 6.35\text{E-06}) = 71^{\circ}\text{F}$

At 10^6 cycles, $S_a = 26 \text{ ksi}$ for SS.

Therefore, significant temperature fluctuations for SS are those for which the total algebraic range exceeds the quantity:

- $26 \div (28,012 \times 9.30\text{E-06}) = 100^{\circ}\text{F}$

These temperature values define what is a significant temperature fluctuation.

The number of significant temperature fluctuations between any two adjacent points during normal operations is assumed to be 5,000; this is chosen as a bounding high value for which the applicable criteria are met without additional detailed analysis. To ensure the assumption of 5,000 cycles is appropriate, a review of allowable plant event transients capable of adding or removing significant energy to the containment for 80-year plant life (as presented in SLRA Tables 4.3.1-1 and 4.3.1-2) is shown below:

- 1250 psig Overpressure: 1 cycle
- 1375psig Overpressure: 1 cycle
- 300F/hr Emergency Cooldown: 10 cycle
- Hydrostatic Pressure Test: 3 cycle
- Design Pressure Test: 130 cycles
- Heatup: 240 cycles
- Cooldown: 229 cycles
- Interruption/Loss of Feedwater Heaters: 80 cycles

- Loss of feedwater flow: 80 cycles
- SCRAM: 280 cycles
- Shutdown Cooling Init. into Isolated Loop: 240 cycles
- EMRV Actuation: 500 cycles
- SRV Blowdown: 1 cycle

Summing these allowable cycle transients together results in 1,793 cycles. Therefore, the assumption of 5,000 cycles is conservative for an 80-year plant life.

This is reasonable given that this evaluation excludes locations for which T exceeds 310°F as per Section 2.2 and therefore includes only locations that are essentially unaffected by process fluid transients.

The temperature-difference during normal operation is assumed to be the difference between the maximum operating temperature (150°F) and the minimum defined temperature (32°F).

The dT between adjacent points is assumed to be 118°F. This is conservative given that (a) no thermal transients are defined for the drywell, and (b) the Class MC portion of penetrations with hot process piping is remote from the process piping as discussed in Section 2.5.

At 5,000 cycles: from ASME Section III, Appendix I, Figure I-9.1, $S_a = 47$ ksi (CS). Therefore, the limit on the temperature-difference for CS is:

- $47 \div (2 \times 27,804 \times 6.35\text{E-}06) = 133^\circ\text{F}.$

At 5,000 cycles, from ASME Section III, Appendix I, Figure I-9.2, $S_a = 70$ ksi (SS). Therefore, the limit on the temperature-difference for SS is:

- $70 \div (2 \times 28,012 \times 9.30\text{E-}06) = 134^\circ\text{F}.$

These temperature-difference limits between adjacent points are greater than the expected temperature-difference fluctuation of 118°F between adjacent points. These results indicate that the drywell and penetrations could experience normal operation temperature differences (between any two adjacent points) of 133°F (CS) and 134°F (SS), 5,000 times over 80 years without exceeding the NE-3222.4(d)(4) threshold.

3.5 Temperature difference – dissimilar materials:

As stated in Section 2.7, some of the evaluated CS penetrations contain SS portions.

As stated in Section 3.3, normal operating $T_{ave} = 132.5^\circ\text{F}$. Parameter values at T_{ave} from ASME Section III, Appendix I, Tables I-5.0 and I-6.0:

- $\alpha_{inst} \text{ (CS)} = 6.35 \text{ E-}06 \text{ in/in/}^\circ\text{F}$
- $\alpha_{inst} \text{ (SS)} = 9.30 \text{ E-}06 \text{ in/in/}^\circ\text{F}$

- $E \text{ (CS)} = 27,804 \text{ ksi}$
- $E \text{ (SS)} = 28,012 \text{ ksi}$

At 10^6 cycles, $S_a = 12.5 \text{ ksi}$ for CS.

For the CS-to-SS interface, a significant T fluctuation is:

- $12.5 \div [2 \times (27,804 \times 6.35\text{E-}06 - 28,012 \times 9.30\text{E-}06)] = 74^\circ\text{F}.$

The expected number of transients in which these dissimilar metal discontinuities experience the maximum temperature fluctuations at this interface is 5,000, consistent with the basis provided in the previous section.

It is assumed that the temperature fluctuation between any two adjacent points during normal operation equals the difference between the maximum operating temperature (150°F) and the minimum defined temperature (32°F) for a temperature differential of 118°F .

At 5,000 cycles: from ASME Section III, Appendix I, Figure I-9.1, $S_a = 47 \text{ ksi}$. Therefore, the limit on the maximum temperature-difference for the CS-to-SS interface is:

- $47 \div [2 \times (27,804 \times 6.35\text{E-}06 - 28,012 \times 9.30\text{E-}06)] = 280^\circ\text{F}$

The temperature-difference limit for the CS-to-SS interface between adjacent points is greater than the expected temperature fluctuation of 118°F . This result indicates that portions of the drywell and penetrations with these dissimilar metals could experience maximum temperature fluctuations stated above 5,000 times over 80 years without exceeding the NE-3222.4(d)(5) threshold.

3.6 Mechanical loads:

This criterion addresses mechanical reactions on the containment and not pressure transients. The allowable 80-year cycle count for various RPV transients is used to reflect mechanical loads introduced on the drywell shell and associated penetrations. This method is considered conservative considering the containment and its penetrations are not expected to undergo loading cycles in excess of those that are experienced by the RPV by means of process piping and other related transients. Significant load fluctuations have been conservatively assumed to be 10,000 cycles. This value is more than the sum of allowable 80-year cycle count for various RPV transients, which is 4,725.

At 10^6 cycles, $S_a = 37 \text{ ksi}$ for CS and $S_a = 59 \text{ ksi}$ for SS. The mechanical load stress range limits at 10,000 cycles are as follows:

- From ASME Section III, Appendix I, Figure I-9.1, $S_a = 37 \text{ ksi}$ (CS)
- From ASME Section III, Appendix I, Figure I-9.2, $S_a = 59 \text{ ksi}$ (SS)

The range of mechanical load stress is assumed to be $1.5S_m$ for the material being analyzed, which is the maximum allowable primary membrane stress for the penetrations (used to represent the maximum allowable stress for the material).

The corresponding mechanical load stresses are:

- ASTM A201 Grade B CS: $1.5 \times 18.8 \text{ ksi} = 28.2 \text{ ksi}$
- ASTM A333 Grade 1 CS: $1.5 \times 17.7 \text{ ksi} = 26.6 \text{ ksi}$
- ASTM A240 Type 321 SS: $1.5 \times 20.0 \text{ ksi} = 30 \text{ ksi}$

Since the mechanical load stress is less than the corresponding S_a for the mechanical load stress range limits, the mechanical load criterion is satisfied.

4.0 Conclusion

As summarized above, all six criteria for a fatigue waiver specified in the ASME Code for Class MC components are satisfied. In accordance with the rules of NE-3222.4(d) of Section III of the ASME Code, the NMP1 drywell shell (including metal plate, airlock, equipment hatch, and drywell penetrations (mechanical and electrical)) within the scope of this evaluation can be considered exempt from detailed fatigue analysis.

3.5.2.2.1.6 Cracking Due to Stress Corrosion Cracking

The SCC of 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 (ASME 2008-TN8166) and 10 CFR Part 50 (TN249), Appendix J, to manage this aging effect. Further evaluation, including consideration of SCC susceptibility and applicable OE related to detection and additional appropriate examinations/evaluations implemented to detect this aging effect for these SS components and dissimilar metal welds is recommended.

Table 3.5.1 Item Number 3.5.1-010 and 3.5.1-039 evaluate cracking due to SCC in stainless steel penetration sleeves, penetration bellows, vent line bellows and dissimilar metal welds (DMWs) exposed to an uncontrolled air environment. Cracking due to SCC is an applicable aging effect for these materials when exposed to temperatures in excess of 140 degrees F. In addition, stainless steel SCC requires a concentration of chloride or sulfate contaminants, which are not present in significant quantities, as well as high stress. Station procedures strictly control the procurement and use of products that could contain contaminants such as chlorides, fluorides, and sulfates, which ensures that stainless steel piping and components are not subject to significant levels of these detrimental contaminants.

The torus and drywell shells at NMP1, as well as containment penetration sleeves, are made of carbon steel and not susceptible to SCC. Connection of stainless steel components to the steel drywell or torus involve DMWs. Stainless steel components of the Primary Containment include: torus thermowells, certain piping penetration flued heads, the refueling bellows, the vent line expansion bellows, and hot piping penetration

expansion bellows. Of these, only the expansion bellows may experience temperatures in excess of the 140 degrees F threshold for SCC during normal operation.

As shown in UFSAR Figure VI-4, high-temperature penetrations have two expansion joints; the outside expansion bellows are designed for double the design stresses of the internal expansion bellows. The expansion bellows are protected by a guard pipe that surrounds the process line, thus eliminating any direct jet impingement on the bellows and drywell nozzle. The bellows accommodate the thermal expansion of the drywell. The bellows are fabricated from stainless steel.

The following Primary Containment penetrations, equipped with stainless steel bellows, are subject to elevated temperatures during normal operation:

Table 3.5.2.2.1.6-1 Primary Containment Penetrations with Stainless Steel Bellows
Subject to Elevated Operating Temperatures

Penetration Number	Description
X-2A	Main Steam
X-2B	Main Steam
X-3A	Emergency Condenser Steam Supply
X-3B	Emergency Condenser Steam Supply
X-4A	Primary Feedwater
X-4B	Primary Feedwater
X-5A	Emergency Condenser Return
X-5B	Emergency Condenser Return
X-7	Shutdown Cooling Return
X-8	Shutdown Cooling Supply
X-9	Cleanup Supply
X-13A	Core Spray
X-14	Core Spray

Additionally, the vent system is relied upon as a pathway for steam between the drywell and the torus in the event of a pipe rupture. The vent system also provides support for a portion of the SRV piping inside the vent line and torus. Loads acting on the SRV piping are transferred to the vent system by the penetration assembly, which is welded to the vent. Each of the vent lines includes a stainless steel expansion bellows assembly.

The enhanced ASME Section XI, Subsection IWE (B.2.1.29) program and the 10 CFR Part 50, Appendix J (B.2.1.31) program will be used to manage cracking due to SCC for stainless steel penetration bellows (hot fluid penetrations), and the associated DMWs. In addition, due to being higher temperature, these penetrations are leading indicators for cyclic load cracking of susceptible drywell shell materials, penetration sleeve, or other locations.

Table 3.5.1 Item Number 3.5.1-038 is not applicable to the NMP1 containment. The item number is only applicable to BWR Mark III containments.

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 to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL, and/or Structures Monitoring AMPs, to manage these aging effects for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-011 is not applicable to the NMP1 Mark I steel containment. As stated in SLRA Section 3.5.2.2.1.1, NMP1 does not have an ASME Section XI, Subsection IWL program. The Primary Containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building and is mounted on support structures that transmit loads to the concrete foundation of the Reactor Building as shown in UFSAR Figures III-10 and V-3. Primary Containment internal concrete is not exposed to air - outdoor or groundwater/soil environments; thus, freeze-thaw is not applicable, and Primary Containment concrete is not subject to loss of material (scaling, spalling) and cracking due to freeze-thaw. Freeze-thaw of Reactor Building concrete is addressed in Section 3.5.2.2.2.1.1 and Table 3.5.1 Item Number 3.5.1-042.

3.5.2.2.1.8 Cracking Due to Expansion from Reaction with Aggregates

Cracking due to expansion from reaction with aggregates could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The GALL-SLR Report recommends further evaluation to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL, and/or Structures Monitoring AMPs to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-012 is not applicable to the NMP1 Mark I steel containment. As stated in SLRA Section 3.5.2.2.1.1, NMP1 does not have an ASME Section XI, Subsection IWL program. Cracking due to expansion from reaction with aggregates for Reactor Building concrete and inaccessible areas of Primary Containment internal concrete elements (i.e., drywell floor and reactor pedestal) is addressed in Section 3.5.2.2.2.1.2 and Table 3.5.1 Item Number 3.5.1-043.

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, to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging

effects. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-014 is not applicable to the NMP1 Mark I steel containment. The concrete containment component types described for Item Number 3.5.1-014 do not exist at NMP1. As stated in SLRA Section 3.5.2.2.1.1, NMP1 does not have an ASME Section XI, Subsection IWL program. The Primary Containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building and is mounted on support structures that transmit loads to the concrete foundation of the Reactor Building as shown in UFSAR Figures III-10 and V-3. The Primary Containment is not subject to a water-flowing environment, which would be conducive to porosity and permeability due to leaching of calcium hydroxide and carbonation. Leaching of calcium hydroxide and carbonation has not been observed in accessible concrete internal to the Primary Containment. Leaching of calcium hydroxide and carbonation of Reactor Building concrete is addressed in Section 3.5.2.2.1.4 and Table 3.5.1 Item Number 3.5.1-047.

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

3.5.2.2.2.1 Aging Management of Inaccessible Areas

1. *Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures. Further evaluation of inaccessible areas of these groups of structures for plants located in moderate to severe weathering conditions is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-042 evaluates the loss of material (spalling, scaling) and cracking due to freeze-thaw for concrete structures. This aging effect (and mechanism) is applicable to normally inaccessible concrete exposed to groundwater/soil and air – outdoor environments. NMP1 is located in a region where weathering conditions are considered severe as shown in ASTM C33, “Standard Specification for Concrete Aggregates.” The Structures Monitoring (B.2.1.33) program will be used to manage loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas of Group 2, 3, 8 and 9. NMP1 does not have any concrete structures categorized as Group 1, 5 or 7 per NUREG-2191.

The original designs and construction of these structures conformed to ACI 318, “Building Code Requirements for Reinforced Concrete”. The concrete mix design provides for low permeability by incorporating fly ash and adequate air entrainment (not less than 3 percent nor more than 6 percent) in the air-outdoor environment such that the concrete has good freeze-thaw resistance.

Plant operating experience has not identified significant loss of material (spalling, scaling) and cracking due to freeze-thaw in accessible areas of the in scope reinforced concrete structures. Where indications of potential loss of material (spalling, scaling) and cracking due to freeze-thaw have been identified, the indications have been minor and do not impact the intended function of the concrete

structures. This operating experience provides objective evidence that the design and construction of external reinforced concrete at NMP1 has provided concrete with good freeze-thaw resistance. Although operating experience has not identified significant loss of material and cracking due to freeze-thaw, the Structures Monitoring (B.2.1.33) program includes inspection for these aging effects in the accessible areas.

The visual inspections of reinforced concrete identify concrete damage in accordance with the requirements of the Structures Monitoring (B.2.1.33) program. If freeze-thaw damage were to occur, it would occur at the surface of concrete with significant moisture levels and sudden drops in temperature to below freezing. In general, these areas are exposed at the ground surface and are accessible for inspection. In addition, NMP1 examines exposed portions of the below-grade concrete, when excavated for any reason, in accordance with the Structures Monitoring (B.2.1.33) program.

If unacceptable conditions due to freeze-thaw are identified in the accessible areas of structures, the conditions are evaluated and (depending upon the initial conditions and evaluation) corrective actions are developed that may include additional inspections to determine the extent of degraded conditions as part of the corrective action program. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

The Structures Monitoring (B.2.1.33) program is expected to adequately manage the cracking due to expansion and reaction with aggregates that could occur in inaccessible reinforced concrete areas of the Group 2, 3, 8, and 9 structures. Therefore, a plant-specific aging management program is not required to manage this aging effect.

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 of inaccessible areas of these groups of structures is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-043 evaluates cracking due to expansion and reaction with aggregates for all concrete structures. This aging effect (and mechanism) is applicable to normally inaccessible portions of reinforced concrete structures at NMP1. The Structures Monitoring (B.2.1.33) program will be used to manage cracking due to expansion and reaction with aggregates in both accessible and inaccessible areas of reinforced concrete for Group 2, 3, 4, 8 and 9 structures. NMP1 does not have any concrete structures categorized as Group 1, 5 or 7 per NUREG-2191. Significant portions of the in-scope structures are accessible, which provides indications of reinforced concrete conditions in inaccessible areas.

Petrographic examinations and alkali reactivity tests performed according with ASTM C295 and ASTM C33-64 verify that the aggregates used during construction are not

reactive. Cement used during construction was low alkali type II portland cement conforming to ASTM C150. Water used for mixing concrete, as well as washing aggregates and other related uses was fresh, clean and free from injurious amounts of sewage, oil, acid, alkali, salts, organic matter and other impurities.

Plant operating experience has not identified cracking associated with expansion due to reaction with aggregates. The Structures Monitoring (B.2.1.33) program requires the inspection and monitoring of reinforced concrete structures for cracking. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected on the surfaces at grade level where the moisture level is higher. In addition, NMP1 examines exposed portions of the below-grade concrete, when excavated for any reason, in accordance with the Structures Monitoring (B.2.1.33) program. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

Significant concrete deformation due to differences in concrete expansion, which can be identified by looking for cracking between concrete elements below and above grade or at visible seismic gaps or expansion joints, has not been observed at NMP1. This provides objective evidence that cracking associated with expansion due to reaction with aggregated has not occurred.

The Structures Monitoring (B.2.1.33) program is expected to adequately manage the cracking due to expansion and reaction with aggregates that could occur in inaccessible reinforced concrete areas of the Group 2, 3, 4, 8, and 9 structures. Therefore, a plant-specific aging management program is not required to manage this aging effect.

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.*

Table 3.5.1 Item Number 3.5.1-044 evaluates cracking and distortion due to increased stress levels from settlement for concrete structures. This aging effect (and mechanism) is applicable to all concrete exposed to soil. The NMP1 CLB does not include a program to monitor concrete for settlement or credit a dewatering system to control building settlement. The Structures Monitoring (B.2.1.33) program will be used to manage cracking and distortion of the reinforced concrete structures that are and are exposed to the groundwater/soil environment. NMP1 does not have any concrete structures categorized as Group 1, 5 or 7 per NUREG-2191.

This aging effect and mechanism are insignificant for the Group 2, 3, 6, 8, and 9 concrete building structures that are founded on bedrock. Cracking and distortion due to settlement has not been identified in NMP1 building structures but shallow foundations for certain Group 3 structures (e.g., Yard Structures outside the power block and Switchyard Structures) may be susceptible. The Structures Monitoring (B.2.1.33) program continues to inspect and monitor concrete structures for cracking and distortion. The condition of accessible and above grade concrete is used as an indicator for the condition of inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. Cracks extending into accessible areas, if any, will be managed by the Structures Monitoring (B.2.1.33) program. If unacceptable conditions due to this mechanism were identified in the accessible areas of structures, procedures require that an extent of condition be determined, and additional inspections or evaluations would address inaccessible and below grade portions of any affected structure. In addition, NMP1 examines exposed portions of the below-grade concrete, when excavated for any reason, in accordance with the Structures Monitoring (B.2.1.33) program.

NMP1 foundation design does not utilize porous concrete foundation or subfoundation material. Thus, differential settlement and erosion of porous concrete subfoundation does not cause reduction in foundation strength and cracking in NMP1 structures and Table 3.5.1 Item number 3.5.1-046 is not used. Aging effects due to settlement are managed under Item Number 3.5.1-044.

4. *Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Groups 1–5 and 7–9 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-047 evaluates increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation for concrete structures. This aging effect (and mechanism) is applicable to normally inaccessible portions of reinforced concrete structures exposed to water-flowing environments at NMP1. The Structures Monitoring (B.2.1.33) program will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Group 2, 3, 8, and 9 structures. Similarly, NMP1 does not have any concrete structures categorized as Groups 1, 5 or 7 per NUREG-2191. This Table 3.5-1 Item Number does not apply to the Group 4 structures due to the Mark I containment design. The Primary Containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building. The Primary Containment is not subject to a water-flowing environment, which would be conducive to porosity and permeability due to leaching of calcium hydroxide and carbonation. Significant portions of the in-scope structures are accessible, which provides indications of reinforced concrete conditions in inaccessible areas.

The NMP1 structural concrete was constructed to minimize the potential effects of leaching of calcium hydroxide and carbonation. The original designs and construction of these structures conformed to ACI 318, “Building Code Requirements for Reinforced Concrete”. The concrete mix design provides for low permeability by incorporating fly ash and approved water-reducing admixtures. Concrete fine and coarse aggregates conform to ASTM C33. The cement is Type I and II, Portland cement conforming to ASTM C150. Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment, and organic matter. Adherence to these standards minimizes the potential effects of leaching of calcium hydroxide and carbonation.

However, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation is applicable for a water-flowing environment (which can include rainwater, raw water, groundwater, or water flowing under a foundation); therefore, the potential for rainwater or groundwater to flow over or collect on reinforced concrete surfaces is considered. Accessible areas can be used as a leading indicator of increase in porosity and permeability and loss of strength of reinforced concrete conditions in inaccessible areas for leaching of calcium hydroxide or carbonation. NMP1 will continue to examine exposed portions of the below-grade concrete, when excavated for any reason in accordance with the Structures Monitoring (B.2.1.33) program. Operating experience at NMP1, which inspects for concrete deterioration due to any aging effect and mechanism, has identified increases in porosity and permeability. Concrete degradation that would indicate a reduction in its structural integrity has not been identified. The inconsequential increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide does not impact the intended functions of the concrete structures.

Inaccessible below-grade reinforced concrete for Group 2, 3, 8, and 9 structures is subject to an aggressive environment. Test results for groundwater samples taken in 2025 confirm chloride levels above the 500 ppm threshold that defines an aggressive environment. High chloride levels are a concern as a potential indicator of reinforcing steel corrosion that could be initially detected as cracking and spalling of the concrete. The groundwater at NMP1 is not aggressive with respect to pH or sulfates. NMP1 will continue to perform periodic groundwater and raw water testing as described in the Structures Monitoring (B.2.1.33) program.

The Structures Monitoring (B.2.1.33) program will continue to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Group 2, 3, 8, and 9 structures. Therefore, a plant-specific aging management program is not required to manage this aging effect.

3.5.2.2.2 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 ACI 349-85, “Code Requirements for Nuclear Safety-Related Concrete Structures,” 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 to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if any portion of the safety-related and other concrete structures exceeds specified temperature limits (i.e., general area temperature greater than 66°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 Section A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-048 is not applicable to NMP1. NMP1 does not have any concrete structures categorized as Groups 1 or 5. Group 2 and 3 structures at NMP1 are not subject to general area normal temperatures greater than 150 degrees F. In addition, local temperatures in excess of 200 degrees F have not been reported at NMP1. Station operating experience has not identified elevated general or local area temperature as a concern for concrete structural components. As described in SLRA Section 3.5.2.2.2.1.2 above, concrete structural components located inside the containment (which include Group 4 structures for NMP1) are not subject to general area temperature greater than 150 degrees F or local area concrete temperature greater 200 degrees F. NMP1 UFSAR Section VI E.1.2 states that the limit of the bulk air temperature inside the drywell during normal plant operation is 150 degrees F. The drywell is cooled during normal operation of the unit by a closed loop ventilation system designed to hold the average temperature to 150 degrees F or lower. The primary containment ventilation system is described in UFSAR Section VI E.1.0 and in SLRA Section 2.3.3.4, Containment Systems.

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

Further evaluation is recommended for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL-SLR Report, AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," or Federal Energy Regulatory Commission (FERC)/U.S. Army Corp of Engineers dam inspection and maintenance procedures.

- 1. Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP to manage these aging effects for inaccessible areas for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-049 evaluates the loss of material (spalling, scaling) and cracking due to freeze-thaw for concrete structures. This aging effect (and mechanism) is applicable to normally inaccessible concrete exposed to groundwater/soil and air – outdoor environments. NMP1 is located in a region where weathering conditions are considered severe as shown in ASTM C33, "Standard Specification for Concrete Aggregates." The Structures Monitoring (B.2.1.33) program will be used to manage loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas of Group 6 structures. Portions of the Screen

and Pumphouse Building are accessible, which provides indications of concrete conditions in the inaccessible areas. The intake tunnel and discharge tunnel is evaluated within the Group 6 Structures and is not susceptible to loss of material (spalling, scaling) and cracking due to freeze-thaw. These stationary structures reside below the frost line and are filled with lake water.

The original designs and construction of these structures conformed to ACI 318, “Building Code Requirements for Reinforced Concrete.” The concrete mix design provides for low permeability by incorporating fly ash and adequate air entrainment (not less than 3 percent nor more than 6 percent) in the air-outdoor environment such that the concrete has good freeze-thaw resistance.

Plant operating experience has not identified significant a loss of material (spalling, scaling) and cracking due to freeze-thaw in accessible areas of in scope reinforced concrete structures. Where indications of potential loss of material (spalling, scaling) and cracking due to freeze-thaw have been identified, the indications have been minor and do not impact the intended function of the concrete structures. This operating experience provides objective evidence that the design and construction of external reinforced concrete at NMP1 has provided concrete with good freeze-thaw resistance. Although operating experience has not identified significant loss of material and cracking due to freeze-thaw, the Structures Monitoring (B.2.1.33) program includes inspection for these aging effects in the accessible areas.

The visual inspections of reinforced concrete identify concrete damage in accordance with the requirements of the Structures Monitoring (B.2.1.33) program. If freeze-thaw damage were to occur, it would occur at the surface of concrete with significant moisture levels and sudden drops in temperature to below freezing. In general, these areas are exposed at the ground surface and are accessible for inspection. In addition, NMP1 examines exposed portions of the below-grade concrete, when excavated for any reason, in accordance with the Structures Monitoring (B.2.1.33) program.

If unacceptable conditions due to freeze-thaw are identified in the accessible areas of structures, the conditions are evaluated and (depending upon the initial conditions and evaluation) corrective actions are developed that may include additional inspections to determine the extent of degraded conditions as part of the corrective action program. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

The Structures Monitoring (B.2.1.33) program is expected to adequately manage the cracking due to expansion and reaction with aggregates that could occur in inaccessible reinforced concrete areas of the Group 6 structures. Therefore, a plant-specific aging management program is not required to manage this aging effect.

2. *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to*

Structures Monitoring AMP, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-050 evaluates cracking due to expansion and reaction with aggregates for Group 6 structures. This aging effect (and mechanism) is applicable to normally inaccessible portions of reinforced concrete structures at NMP1. The Structures Monitoring (B.2.1.33) program will be used to manage cracking due to expansion and reaction with aggregates in both accessible and inaccessible areas of reinforced concrete for Group 6 structures. Significant portions of the in-scope structures are accessible, which provides indications of reinforced concrete conditions in inaccessible areas.

Petrographic examinations and alkali reactivity tests performed in accordance with ASTM C295 and ASTM C33-64 verify that the aggregates used during construction are not reactive. Cement used during construction was low alkali type II portland cement conforming to ASTM C150. Water used for mixing concrete, as well as washing aggregates and other related uses was fresh, clean and free from injurious amounts of sewage, oil, acid, alkali, salts, organic matter, and other impurities.

Plant operating experience has not identified cracking associated with expansion due to reaction with aggregates. The Structures Monitoring (B.2.1.33) program requires the inspection and monitoring of reinforced concrete structures for cracking. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected on the surfaces at grade level where the moisture level is higher. In addition, NMP1 examines exposed portions of the below-grade concrete, when excavated for any reason, in accordance with the Structures Monitoring (B.2.1.33) program. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

Cracking associated with expansion due to reaction with aggregates has not been observed in NMP1 Group 6 concrete structures. Nevertheless, the Structures Monitoring (B.2.1.33) program continues to inspect and monitor Group 6 concrete structures for cracking. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected on the surfaces of the Group 6 structures continuously exposed to water. In addition, NMP1 examines exposed portions of the below-grade concrete, when excavated for any reason, in accordance with the Structures Monitoring (B.2.1.33) program. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function.

Significant concrete deformation due to concrete expansion has not been detected in the Screen and Pumphouse Building, which has comparatively high exposure to water compared to other reinforced concrete structures at NMP1. This provides objective evidence that that cracking associated with expansion due to reacting with aggregates has not yet occurred.

The Structures Monitoring (B.2.1.33) program is expected to adequately manage the cracking due to expansion and reaction with aggregates that could occur in inaccessible reinforced concrete areas of the Group 6 structures. Therefore, a plant-specific aging management program is not required to manage this aging effect.

3. *Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).*

Table 3.5.1 Item Number 3.5.1-051 evaluates increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation for Group 6 concrete structures. This aging effect (and mechanism) is applicable to normally inaccessible portions of reinforced concrete structures exposed to water-flowing environments at NMP1. The Structures Monitoring (B.2.1.33) program will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Group 6 structures. Significant portions of the in-scope structures are accessible, which provides indications of reinforced concrete conditions in inaccessible areas.

The NMP1 structural concrete was constructed to minimize the potential effects of leaching of calcium hydroxide and carbonation. The original designs and construction of these structures conformed to ACI 318, "Building Code Requirements for Reinforced Concrete." The concrete mix design provides for low permeability by incorporating fly ash and approved water-reducing admixtures. Concrete fine and coarse aggregates conform to ASTM C33. The cement is Type I and II, Portland cement conforming to ASTM C150. Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment, and organic matter. Adherence to these standards minimizes the potential effects of leaching of calcium hydroxide and carbonation.

However, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation is applicable for a water-flowing environment (which can include rainwater, raw water, groundwater, or water flowing under a foundation); therefore, the potential for rainwater or groundwater to flow over or collect on reinforced concrete surfaces is considered. Accessible areas can be used as a leading indicator of increase in porosity and permeability and loss of strength of reinforced concrete conditions in inaccessible areas for leaching of calcium hydroxide or carbonation. NMP1 will continue to examine exposed portions of the below-grade concrete, when excavated for any reason in accordance with the Structures Monitoring (B.2.1.33) program. Operating experience at NMP1, which inspects for concrete deterioration due to any aging effect and mechanism, has identified increases in porosity and permeability. Concrete degradation that would indicate a reduction in its structural integrity has not been identified. The inconsequential increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide does not impact the intended functions of the concrete structures.

Inaccessible areas of concrete elements for Group 6 structures are subject to the aggressive environment described in SLRA section 3.5.2.2.2.1.4 above. NMP1 will continue to perform periodic groundwater and raw water testing as described in the Structures Monitoring (B.2.1.33) program.

The Structures Monitoring (B.2.1.33) program will continue to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Group 6 structures. Therefore, a plant-specific aging management program is not required to manage this aging effect.

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 SCC and loss of material due to pitting and crevice corrosion could occur in: (i) Group 7 and 8 SS tank liners exposed to standing water and (ii) 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 Section 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: (i) the plant specific OE does not reveal a history of pitting or crevice corrosion or cracking and (ii) 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, 6063-T6, 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.

Item Number 3.5.1-052 is not applicable to NMP1. NMP1 does not have Group 7 and 8 stainless steel tank liners exposed to standing water.

Item Number 3.5.1-099 evaluates cracking due to SCC and loss of material due to pitting and crevice corrosion for aluminum and stainless steel support members, welds, bolted connections, and support anchorage to building structures associated with ASME Code piping and components. These aging effects (and mechanisms) are applicable to support components (e.g., support members, welds, bolted connections, support anchorage to building structure, constant and variable load spring hangers, rod hangers, clamps, straps, guides, stops, seismic anchors or restraints, support frames, or bolting) exposed to air – indoor environments where sufficient halides (e.g., chlorides) and moisture are present. Stainless steel structural components and bolting are limited in number in comparison to the amount of stainless steel mechanical components at NMP1. There has been no site operating experience of cracking or localized corrosion for stainless steel supports associated with ASME Class 1, 2, or 3 piping and components exposed to air environments, or as a result of exposure to secondary sources, indicating that the environments at NMP1 do not contain sufficient halides in the presence of moisture to result in SCC. However, periodic visual examinations conducted in accordance with the ASME Section XI, Subsection IWF (B.2.1.30) program will be performed to confirm that loss of material due to pitting and crevice corrosion or cracking due to SCC are not occurring at a rate that affects the intended function of these SS components. There are no aluminum support members in scope under this item number.

Item Number 3.5.1-100 evaluates cracking due to SCC and loss of material due to pitting and crevice corrosion for aluminum and stainless steel support members, welds, bolted connections, and support anchorage to building structures associated with cable trays, conduit, heating, ventilation, and air-conditioning ducts, TubeTrack, instrument tubing, containment closure bolting and non-ASME Code piping and components. These aging effects (and mechanisms) are applicable to support components (e.g., support members, welds, bolted connections; support anchorage to building structure, anchor bolts, structural bolting) exposed to air – indoor and air – outdoor environments where sufficient halides (e.g., chlorides) and moisture are present. Additional stainless steel component types (e.g., insulation jacketing and associated clamps/bands/fasteners, refueling bellows inside Primary Containment) and aluminum component types (e.g., insulation jacketing, new fuel storage racks, siding, and spent fuel pool gates) at NMP1 are also addressed by this Table 3.5.1 Item Number.

Plant-specific operating experience has not revealed a history of cracking or localized corrosion for aluminum or stainless steel components or support connections. Except as noted below, periodic visual inspections conducted in accordance with the StructuresMonitoring (B.2.1.33) program will continue to be performed to confirm that loss of material due to pitting and crevice corrosion or cracking due to SCC are not occurring at a rate that affects the intended function of these components. The One-

Time Inspection (B.2.1.20) program will be used to manage cracking and loss of material for stainless steel refueling bellows assemblies and closure bolting exposed to air-indoor environments in the Primary Containment drywell, and aluminum and stainless steel insulation jacketing on piping exposed to air-indoor and air-outdoor environments. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) will be used to manage cracking and loss of material for the aluminum and stainless steel fuel prep machine and associated structural bolting.

3.5.2.2.2.5 Cumulative Fatigue Damage

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 TLAAAs as defined in 10 CFR 54.3 (TN4878) only if a CLB fatigue analysis exists. The TLAAAs 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," 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 TLAAAs.

Table 3.5.1 Item Number 3.5.1-053 is not applicable to NMP1. The NMP1 CLB contains no fatigue analysis for Groups B1.1, B1.2, and B1.3 component supports, which are screened under Component Supports Commodity. A CLB fatigue analysis does not exist for support members, welds, bolted connections, or support anchorages to building structures. Therefore, a TLAA is not required to be evaluated in accordance with 10 CFR 54.21(c) for these components.

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 RV 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 plants. However, based on literature review of existing research, radiation fluence limits of 1×10^{19} neutrons/cm² neutron radiation and 1×10^8 Gray (1×10^{10} rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly (NRC 1997-TN8051, NRC 1988-TN8052, NRC 2013-TN8036).

Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to selected existing AMPs to manage the aging effects of irradiation if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy $E > 0.1$ MeV) or gamma radiation exceeds the respective threshold level during the subsequent period of extended operation that could affect intended functions. Higher fluence or dose levels may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and/or loss of mechanical properties of concrete from those fluence levels, at or above the operating temperature experienced by the concrete, and the

effects are applied to the design calculations. Supporting calculations/analyses, test data, and other technical basis are provided to estimate and evaluate fluence levels and the plant-specific program. The acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

Item Number 3.5.1-097 addresses the potential for reduction of strength, loss of mechanical properties, and cracking due to irradiation of concrete in the reactor cavity area proximate to the reactor pressure vessel (RPV). At NMP1, this aging effect (and mechanism) primarily concerns the reactor shield wall around the RPV in the drywell. Radiation interactions with material and radiation-induced heating to structures and components are much less than those affecting the reactor shield wall at the RPV beltline region.

UFSAR Figure V-3 illustrates an elevation view of the reactor pressure vessel, supporting concrete pedestal, and reactor shield wall within the drywell. The RPV is supported from the bottom by a skirt mounted on the reinforced concrete reactor pedestal structure, which also supports the reactor shield wall. The reactor shield wall, surrounding the reactor vessel, is a 2-foot-thick hollow cylinder of concrete with 5/8-inch-thick steel liner plates covering its interior and exterior surfaces. The reactor shield wall is approximately 45 feet tall. The reactor shield wall is described in UFSAR Section XII B.1.2.1, and the construction details of the reactor shield wall are shown on UFSAR Figure XVI-17.

The calculated maximum fluence level is 1.32×10^{18} neutrons/cm² (fluence cutoff energy $E > 0.1$ MeV) at the concrete surface adjacent to the reactor shield wall interior plate for the 67 EFPY projected for the SPEO. By comparison, the calculated neutron fluence level for the reactor pedestal is 9.18×10^{15} neutrons/cm². This evaluation makes use of the NRC approved BWR fluence calculation methodology (ADAMS Accession No. ML032760696), which utilizes a three-dimensional discrete ordinates transport model to estimate peak neutron fluence regarding potential concrete damage. The analysis is consistent with RG 1.190, and the calculations have been benchmarked to plant-specific BWR data. The calculated maximum fluence level for NMP1 is within the NUREG-2192 threshold limit of 1×10^{19} neutrons/cm². Since the neutron fluence is below the NUREG-2192 threshold limit, potential effects from radiation induced volumetric expansion of the aggregates in the concrete are expected to be negligible.

A separate analysis was performed to evaluate a representative and bounding gamma dose for the NMP1 reactor shield wall. This analysis considers radiation sources including gamma dose from the core and secondary gamma dose. The maximum calculated gamma dose projected at 67 EFPY is 3.23×10^9 rad concrete at the inner concrete region of the reactor shield wall. The largest contribution to the concrete dose is from the core, and the second largest is from the vessel activation, which is approximately 28 times lower than the dose from the core. By comparison, the maximum gamma dose computed at the surface of supporting reactor pedestal is 1.40×10^8 rad concrete. For NMP1, the peak gamma dose value at 67 EFPY at the inner concrete region of the reactor shield wall at the RPV beltline does not surpass the NUREG-2192 threshold limit of 1×10^{10} rad concrete.

The results of both irradiation evaluations support the conclusion that the integrity of the reactor shield wall concrete is assured, and that no additional aging management

beyond periodic inspections in accordance with the current Structures Monitoring (B.2.1.33) program is necessary to address the potential for reduction of strength, loss of mechanical properties, and cracking due to irradiation. As demonstrated above, the projected neutron fluence and gamma dose received by any portion of the reactor shield wall concrete remain below the NUREG-2192 threshold limits during the SPEO. Therefore, a plant-specific aging management program is not required to manage this aging effect.

3.5.2.2.2.7 Loss of Material, and/or Changes in Material Properties Due to Weathering, Chemical Degradation, Insect Infestation, Repeated Wetting and Drying, or Fungal Decay

Loss of material and/or changes in material properties due to weathering, chemical degradation, insect infestation, repeated wetting and drying, or fungal decay could occur in standing wooden poles. Their vulnerability to decay is generally dependent on geographical location and site-specific characteristics and conditions. Factors affecting the service life of the wooden poles are the species of wood, type and thoroughness of treatment, geographical location, and soil conditions.

Further evaluation is recommended to determine the plant-specific AMP or plant-specific enhancements to an existing AMP(s) required to manage the effects of aging for wooden poles during the subsequent period of extended operation. A plant-specific AMP or plant-specific enhancements to an existing AMP(s) is acceptable if visual inspections are supplemented with appropriate additional examination methods or techniques, at a frequency capable of detecting the presence and extent of aging effects that are expected in portions of wooden poles that are below-grade and/or internally before there is a loss of intended function. This should account for the decay/deterioration expected to occur at the site based on geographical location and site-specific characteristics and conditions. The plant-specific AMP or plant-specific enhancements to an existing AMP(s), should provide appropriate acceptance criteria and corrective actions, consistent with industry guidelines. The acceptance criteria are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5.1-101 is not applicable to NMP1. There are no wooden poles in scope of this SLRA.

3.5.2.2.2.8 Combined Effects of Aging Associated with Irradiation of RV Steel Structural Support Components and Loss of Function of Other RV Structural Support Components That are Not Concrete

Combined effects of aging associated with neutron radiation exposure could occur in the RV structural support assembly components and materials in BWRs and PWRs. The steel components of the RV structural support assembly (including associated weldments and bolted connections) are made of ferritic carbon or low alloy steels, and the combined effects of aging for these steel components include, but are not limited to, reduction in fracture toughness, loss of material, loss of preload, and distortion that could result in loss of intended function. Examples of RV steel structural support components are RV steel girder and column supports, RV steel support skirt, and neutron shield tanks. For nonconcrete, nonmetallic materials (e.g., Lubrite® lubricant) and nonconcrete, nonferrous materials (e.g., manganese bronze alloy) associated with the RV structural

support assembly, effects of aging due to radiation exposure could also result in loss of intended function. Further evaluation of the RV structural support assembly as a whole is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to selected GALL-SLR AMPs to manage combined effects of aging, such that intended function(s) of the RV structural support assembly as a whole is maintained consistent with the CLB for the subsequent period of extended operation (SPEO).

The acceptance criteria for a plant-specific AMP or enhancements to GALL-SLR AMPs for ongoing management of potential combined effects of aging are described in BTP RLSB-1 (Appendix Section A.1 of this SRP-SLR). The combined effects of aging associated with irradiation (i.e., reduction in fracture toughness, loss of material, loss of preload, and distortion) in the RV structural support assembly components may be addressed by analysis or by augmented ongoing examinations and inspections for the effects of aging, as needed, or a combination of these, during the SPEO. Any analysis should include conservatism in the technical basis (or bases) that account for uncertainties in the evaluation parameters (e.g., fluence, initial nil-ductility temperature, and fracture toughness).

Prior to any analysis, evaluation of the physical conditions through physical examination of the RV structural supports is essential for assessing whether the structural integrity of the RV structural support assembly (other than concrete) is affected by potential combined effects of radiation exposure that include reduction in fracture toughness, corrosive environment (boric acid), temperature, cyclic loading, and applied stresses (including weld residual and/or fabrication stresses). Inservice inspection for flaws in portion of support beams embedded in the concrete biological shield wall may be unattainable; however, inspection records indicating distortions may shed light on the likelihood of significant flaws that may have developed inside the concrete. One or more existing AMPs (e.g., ASME Section XI, Subsection IWF AMP, Boric Acid AMP) may be credited for this physical examination. Following the physical examination, NUREG-1509, "Radiation Effects on Reactor Pressure Vessel Supports," (Johnson and Lipinski 1996-TN8139) provides one acceptable methodology (with the exception of the structural consequence analysis approach in Section 4.5 of the report) for evaluating the RV steel structural support assembly for reduction in fracture toughness due to irradiation embrittlement during the SPEO. An initial screening methodology in NUREG-1509 (Section 4.2) provides one acceptable method for initial assessment for the potential for irradiation embrittlement of the RV steel support system components based on the plant-specific reactor support configuration, plant-specific materials, and plant-specific state of stress. If irradiation embrittlement is a possibility based on this initial screening, an evaluation of the RV steel structural support assembly for a reduction in fracture toughness can be based on a fracture mechanics analysis or a transition temperature analysis (relative to the lowest operating or service temperature of the RV steel structural support component), such as those outlined in Section 4.3 of NUREG-1509, or an accurate analysis such as that outlined Section 4.4 of NUREG-1509. Guidance on the use of NUREG-1509 generic nil-ductility transition temperature (NDTT) values is as follows: if the initial NDTT values of the plant-specific support materials are available, then the plant-specific values should be used. If plant-specific initial NDTT values are not available, and if the plant-specific support material is one of the types/grades of steels in Table 4-2 of NUREG-1509, the generic initial NDTT values in Table 4-1 of NUREG-1509 may be used with 1.3 times the standard deviation. If plant-specific initial NDTT values

are not available, and if the plant-specific support material is not one of the types/grades of steels in Table 4-2 of NUREG-1509, the generic initial NDTT values in Table 4-1 of NUREG-1509 with 1.3 times the standard deviation may be used provided that justification is included (e.g., chemical composition, mechanical properties, manufacturing process, fracture toughness, initial NDTT values from published sources) that demonstrates the plant-specific support material is similar to the corresponding type/grade of steel in Table 4-2 of NUREG-1509. In such a case, applicants can use a bounding approach in their fracture analysis, selecting the most conservative values from available data and references, other further evaluation methodologies, including augmented inspections and examinations.

In the event the applicant pursues augmented ongoing examinations and inspections as needed from one or more GALL-SLR AMPs that help detect the effects of aging for the RV structural support assembly components, including but not limited to cracking, loss of material, loss of preload, and permanent distortion, the details of these augmented ongoing examinations and inspections need to be provided as part for this further evaluation so that the effects of aging are adequately managed consistent with 10 CFR 54.21(a)(3) and that the intended function(s) remain consistent with the CLB for the SPEO.

A plant-specific AMP or plant-specific enhancements to selected GALL-SLR AMPs may not be necessary for the RV steel structural support components if either the initial screening criteria (such as those in Section 4.2.4 of NUREG-1509) or the evaluation criteria (such as those in Section 4.3 or Section 4.4 of NUREG-1509) are satisfied based on plant-specific evaluations. For the radiation exposure criterion in Section 4.2.4 of NUREG-1509, the plant-specific radiation exposure level at a specific location in the RV steel structural supports can be considered low if the radiation exposure damage level is 1×10^{-4} displacements per atom (dpa) or less, consistent with the upper-bound embrittlement shift curve specified in Figure 3-1 of NUREG-1509 and considering an energy spectrum of $E > 0.1$ MeV. The ASTM International Standard E693-17 (ASTM 2017-TN8145) provides a methodology for calculating damage (i.e., dpa) for iron and ferritic low alloy steels.

The radiation exposure evaluation of the RV structural support assembly as a whole should be for an energy spectrum of $E > 0.1$ MeV and use conservative assumptions to estimate the levels of neutron fluence exposure to calculate the projected dpa damage for the SPEO. Evaluation methodologies that have been endorsed by the NRC may be used, but justifications should be provided for their applicability beyond the basis for qualification and approval (e.g., differences in areas of exposure and location(s) for which a methodology was benchmarked against). For evaluation methodologies not previously reviewed or endorsed by the NRC, the applicant provides a detailed description of the analysis methodology and how it was qualified to determine its adequacy for use.

Based on the results of the radiation exposure evaluation, the applicant evaluates the structural integrity of the RV steel structural support components for a reduction in fracture toughness if the radiation exposure damage level exceeds 1×10^{-4} dpa. Additionally, the applicant considers effects of aging associated with irradiation working in synergy with reduction in fracture toughness of the RV steel structural support components such that these components will maintain their intended function(s).

consistent with the CLB through the SPEO. The structural integrity evaluation should include all RV structural support design-basis load combinations in the updated final safety analysis report. The irradiation embrittlement predictions of the RV steel structural support assembly components consider their chemical composition to determine the influence of alloying elements, such as copper, nickel, and phosphorous, on reduction in fracture toughness. For nonconcrete, nonmetallic, nonferrous components and/or materials, the applicant provides supporting technical information and data used to determine their integrity against loss of intended function as a result of radiation exposure and to determine the need for a plant-specific AMP or enhancements to selected GALL-SLR AMPs to manage the combined effects of aging associated with irradiation during the SPEO.

Risk-informed, performance-based (RIPB) principles can be used in the evaluation of the RV steel structural support assemblies with safety being the ultimate objective to maintain RV support intended function consistent with the CLB during the SPEO. RIPB relies on damage tolerance and performance outcomes based on CLB engineering loading demand parameters for events of defined magnitude with uncertainty estimates. This means the applicant ensures that after examination or inspection the results are assessed and uncertainty in the evaluation parameters (e.g., fluence, initial nil-ductility temperature, fracture toughness) are incorporated, margins remain in load-bearing capacity in the RV steel structural support assembly system, such that if performance criteria are not met a safety concern will not develop during the SPEO. Applicants using RIPB principles need data to support their determination of reasonable assurance that the RV steel structural support assembly system will fulfill its intended function through the end of the SPEO. Thus, assumptions in the RIPB evaluation of the RV steel structural support assemblies reflect in situ conditions for material, environment, and component behavior subject to noted uncertainties. The RIPB methodology could be fulfilled, for example, by a combination of ongoing inspections and fracture mechanics with adjustment to uncertainties involved in estimation of damage tolerance. Damage tolerance is a method of assessing the ability of a RV steel structural support assembly component to perform its intended function in the presence of a defect, damage, or flaw. Specifically, damage tolerance is assessing how damage to an RV steel structural support assembly component is tolerated when it fails and evaluating the subsequent redistribution of loads within the RV steel structural support assembly.

Table 3.5.1 Item Number 3.5.1-103 is not applicable to NMP1. There are no sliding surfaces or special components exposed to aging effects due to irradiation.

Item Number 3.5.1-102 addresses the reduction in fracture toughness and/or loss of intended function of reactor pressure vessel (RPV) support steel due to irradiation embrittlement. At NMP1, this aging effect (and mechanism) primarily concerns the reactor shield wall around the RPV in the drywell. Radiation interactions with material and radiation-induced heating to structures and components are much less than those affecting the reactor shield wall at the RPV beltline region.

The RPV support structures at NMP1 are described in UFSAR Section V B.2.0. The RPV support structures consist of a cylindrical skirt attached to the bottom head of the reactor vessel and lateral stabilizer brackets located below the vessel flange. The lateral stabilizer brackets are connected to tension bars with flexible couplings. The tension bars are, in turn, connected to the top of the reactor shield wall (See UFSAR Figures V-3

and XVI-17). The base of the RPV support skirt is continuously supported by a ring girder and a sole plate fastened to a concrete pedestal, which carries the load through the drywell to the Reactor Building foundation slab. The interior surface of the concrete pedestal is lined with a carbon steel liner plate.

The reactor shield wall, surrounding the reactor vessel, is a 2-foot-thick hollow cylinder of concrete with 5/8-inch-thick steel liner plates covering its interior and exterior surfaces. The reactor shield wall, which is approximately 45 feet tall, is supported on the same concrete pedestal as the RPV. The top of the reactor shield wall is covered by a channel-shaped ring girder. The ring girder is anchored by rigid bars to the drywell walls. The reactor shield wall is described in UFSAR Section XVI B.2.6 and shown on UFSAR Figure XVI-17. In general, the reactor shield wall has been analyzed as a double-walled cylinder simply supported at its ends and pressurized internally. Both the interior and exterior steel liner plates are stressed in tension due to internal pressure. Since the loading distribution between the interior and outer plates was within 5 percent, they were assumed equal. The plates are connected to steel columns by continuous 3/8-inch fillet welds on the interior plate and intermittent 5/16-inch fillet welds on the exterior plate. Components of the containment systems must be designed and operated so that no substantial pressure or thermal stress will be imposed on the structural materials unless the temperatures are well above the nil-ductility temperatures (NDT). For ferritic materials of the containment, the minimum temperature is NDT plus 30 degrees Fahrenheit.

The following RPV steel support components were evaluated against the NUREG-1509 Section 4.2.4 criterion: reactor support skirt, reactor shield wall interior plate, stabilizer, and ring girders. In accordance with NUREG-2192, the plant-specific radiation exposure level at a specific location in the RPV steel structural supports can be considered low if the radiation exposure damage level is 1×10^{-4} displacements per atom (dpa) or less. The NRC approved BWR fluence calculation methodology (ADAMS Accession No. ML032760696), which utilizes a three-dimensional discrete ordinates transport model, shows that there is one steel component (the reactor shield wall interior plate) that exceeds this threshold with a value of 6.03×10^{-4} dpa. By comparison, the ring girder on top of the reactor shield wall, has the next highest exposure damage level of 3.81×10^{-5} dpa, which is below the threshold limit. Note that all other steel structural elements have lower exposure damage level than this ring girder. As a result, a NUREG-1509 evaluation was subsequently performed for the reactor shield wall interior plate.

NUREG-1509 is a resource for addressing the potential effects of irradiation on the steel elements of the reactor shield wall for SLR. Accordingly, a further evaluation of the reactor shield wall interior liner plate for radiation induced embrittlement is provided below. In accordance with NUREG-1509, the reduction in fracture toughness assessment of the reactor shield wall steel can be based on a transition temperature analysis. The transition temperature approach is based on the proposition that catastrophic failure by brittle fracture can be avoided by maintaining the normal operating reactor shield wall service temperature above the NDT temperature of the steel. When using the transition temperature to evaluate the reactor shield wall integrity, the NDT temperature at EOL should include the irradiation induced shift.

The reactor shield wall interior plate is made from ASTM A36 steel. Since there is no test data available for NMP1 RPV structural steel components, which could be used to

establish the initial NDT, the conservative generic values of NUREG-1509 Tables 4.1 and 4.2 are used. The value of the NDT temperature used in this evaluation is NDT mean plus 1.3 standard deviation. Based on the carbon-manganese (hot rolled) data for ASTM A36 steel, the NDT plus 1.3 standard deviation temperature is 39 degrees F. NMP1 UFSAR design criterion 11 requires an additional 30 degrees F margin to be applied to ferritic materials of the containment. Therefore, the initial NDT temperature used in the NUREG-1509 evaluation is 69 degrees F.

NUREG-1509 provides a method for approximating the NDT shift by determining exposure in terms of displacements per atom (dpa), and then using Figure 3-1 (of NUREG-1509) to establish the irradiation induced shift of the NDT. By fitting the experimental data in NUREG-1509, a trend curve prediction model was developed for embrittlement shift versus displacements per atom (dpa) that incorporated the effects of flux and fluence, irradiation temperature, and gamma heating for application to the vessel supports as shown by the upper bound line in NUREG-1509 Figure 3-1. That model included an upper bound transition temperature shift that was adjusted with zero-degree shift at a dpa of 10^{-5} . For this evaluation of the reactor shield wall liner plate, the use of the NUREG-1509 trend curve model for NDT shift versus dpa is very conservative for the following reasons: i) there is a very little copper in the ASTM A36 materials, and ii) the ratio of low energy neutrons to fast neutrons in the reactor shield wall is much smaller than that used in the test reactor experiments.

For this further evaluation, fluence calculations were performed to confirm the attenuation effects through the RPV internals, the RPV and outward to the reactor shield wall. The peak fluence at the reactor shield wall interior surface for 67 EFY equates to 6.03×10^{-4} dpa.

The prediction of the potential irradiation induced NDT shift using the NUREG-1509 Figure 3-1 is described below. The potential irradiation induced NDT shift is a function of the dpa fluence as shown in the figure. The dashed upper bound curve is based on the fit to the experimental test data for reactor vessel carbon steel support materials under low temperature, low flux neutron exposure conditions. For the reactor shield wall with a peak inner diameter surface fluence equating to 6.03×10^{-4} dpa, the corresponding NDT shift is 45 degrees F. Therefore, the total adjusted NDT (EOL NDT) is 114 degrees F. The minimum average bulk average temperature of the Drywell during normal operation is 115 degrees F (UFSAR Section VI E.1.2). Note that plant operating experience has shown that the average reactor shield wall temperatures are at least 15 degrees F higher (>130 degrees F) than the minimum average bulk drywell temperature. Since the EOL NDT is less than the minimum average bulk average drywell temperature, the reactor shield wall interior plate is adequate through SPEO (67 EFY).

Welding of the reactor shield wall was performed in accordance with the original design specifications and the construction records that required the use of E-7018 electrodes in accordance with the relevant AWS specifications, and do not incorporate a copper covering on the electrode. The original specification did not specifically add requirements for any additional copper or nickel and there are no chemical measurements for copper or nickel in material receipt records for the well rods used for the NMP1 reactor shield wall beyond the standard material requirements, which do not include requirements for copper or nickel. As a result, the weld materials are conservatively considered to be similar to the ASTM A36 materials, therefore the same

conclusions are made regarding the potential effects of irradiation induced embrittlement for the weld materials incorporated into the reactor shield wall as were made regarding the reactor shield wall steel elements.

An evaluation of the potential effects of the irradiation on the steel elements of the reactor shield wall was performed for NMP1, using the projected fluence values for 67 EFPY and an adjusted NDT for the steel materials using the methodology in NUREG-1509. The evaluation demonstrates that there is margin between the normal operating temperature and the ductile-to-brittle fracture mode transition temperature that was adjusted for the potential effects due to irradiation. The evaluation concludes that the potential effects due to irradiation on the steel elements of the reactor shield wall materials, including the welding material, are not significant. As a result, the integrity of the reactor shield wall is assured, and no additional aging management of the reactor shield wall beyond the current Structures Monitoring (B.2.1.34) program is necessary for aging effects due to irradiation during the SPEO at NMP1.

In accordance with NUREG-1509 Section 4.3.1, physical examination is essential to reevaluation. The most recent plant operating experience has revealed areas of light corrosion on the reactor shield wall with no sign of pitting. In general, structural steel components including the reactor stabilizers are in good condition with no noted degradation. Accordingly, there is reasonable assurance that a loss (or reduction) of fracture toughness due to irradiation embrittlement will not affect the ability of the reactor shield wall support steel to perform its component intended functions through the SPEO. Since the radiation dose of the reactor shield wall bounds other Class 1 steel structures at NMP1 and the aging effects due to irradiation are not significant for the reactor shield wall, a plant-specific program is not necessary to manage the aging effects due to irradiation of structural steel components.

Additionally, plant operating experience has not identified consequential degradation in the reactor vessel steel supports. Therefore, the integrity of the reactor vessel supports is assured, and no additional aging management of the reactor vessel supports beyond the current ASME Section XI, Subsection IWF (B.2.1.31) program is necessary for aging effects due to irradiation during the SPEO. Accordingly, there is reasonable assurance that a loss (or reduction) of fracture toughness due to irradiation embrittlement will not affect the ability of the RPV support steel to perform its component intended functions through the SPEO.

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 Section B.1.3.

3.5.2.2.4 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.6 and Appendix B, Section B.1.4.

3.5.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Structures and Component Supports:

- Section 4.6, Primary Containment Fatigue Analyses

3.5.3 CONCLUSION

The Structures and Component Supports that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Structures and Component Supports are identified in the summaries in Section 3.5.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Structures and Component Supports components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 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	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.1.
3.5.1-003	Concrete: dome; wall; basemat; ring girders; buttresses, concrete: containment; wall; basemat, concrete: basemat, concrete fill-in annulus	Reduction of strength and modulus of elasticity due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program or AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring," enhanced as necessary.	Yes	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 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	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.3.1.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.3.1.
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	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of material of steel elements in the torus shell as well as the vent system lines, header, deflector, and bellows exposed to air – indoor, uncontrolled and treated water environments. See Subsection 3.5.2.2.1.3.2. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of material of the carbon steel penetration - torus mechanical and steel elements: downcomers exposed to air - indoor uncontrolled and treated water environments. See Subsection 3.5.2.2.1.3.3. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.
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	Not applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.4.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. Fatigue is a TLAA evaluated in SLRA Section 4.6. See Subsection 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	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage cracking of the carbon steel; dissimilar metal welds, and stainless steel penetrations (drywell mechanical - flued heads, bellows) exposed to air - indoor uncontrolled in the Primary Containment. See Subsection 3.5.2.2.1.6. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program or AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.7.
3.5.1-012	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment, concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program or AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.8.
3.5.1-013	This item number is not listed in NUREG-2192.				
3.5.1-014	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S2, "ASME Section XI, Subsection IWL," and/or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.9.
3.5.1-015	This item number is not listed in NUREG-2192.				

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. NMP1 is a Mark I steel containment.
3.5.1-017	This item number is not listed in NUREG-2192.				
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	Not Applicable. NMP1 is a Mark I steel containment.
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	Not Applicable. NMP1 is a Mark I steel containment.
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. NMP1 is a Mark I steel containment.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. NMP1 is a Mark I steel containment.
3.5.1-022	This item number is not listed in NUREG-2192.				
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	Not Applicable. NMP1 is a Mark I steel containment.
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	Not Applicable. NMP1 is a Mark I steel containment.
3.5.1-025	This item number is not listed in NUREG-2192.				

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-026	Moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S1, "ASME Section XI, Subsection IWE"	No	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of sealing of the elastomers - moisture barriers (caulking, flashing and other sealants) exposed to air - indoor uncontrolled in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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," or AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage cracking of the carbon steel, stainless steel, dissimilar metal welds, penetrations (containment - spares, access manholes, inspection ports), penetrations (containment electrical), penetrations (drywell mechanical), penetrations (drywell mechanical - flued heads, bellows), penetration sleeves, personnel airlock, drywell emergency airlock, equipment hatch, steel elements: drywell - shell, head, embedded and sandpocket regions (accessible and inaccessible areas), steel elements: vent line, header, deflector, and bellows exposed to air – indoor uncontrolled in the Primary Containment. See Subsection 3.5.2.2.1.5. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of material of the carbon steel personnel airlock, drywell emergency airlock, and equipment hatch exposed to air - indoor uncontrolled in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.
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 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of leak tightness of the carbon steel personnel airlock, drywell emergency airlock: locks, hinges, and closure mechanisms exposed to air - indoor uncontrolled in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of preload of carbon and low alloy steel bolting and stainless steel bolting (containment closure) exposed to air - indoor uncontrolled in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.
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 with exceptions. The ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of material of carbon and low alloy steel bolting (containment closure) exposed to air - indoor uncontrolled in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.
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. NMP1 is a Mark I steel containment.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S4, "10 CFR Part 50, Appendix J "	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.1.31) program will be used to manage loss of sealing of the elastomers (seals and gaskets) exposed to air - indoor uncontrolled in the Primary Containment.
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. The Protective Coating Monitoring and Maintenance (B.2.1.35) program will be used to manage loss of coating or lining integrity of the Service Level I coatings exposed to air - indoor uncontrolled and treated water environments in the Primary Containment.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-035	Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, drywell shell; drywell head; drywell shell in sandpocket 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	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of material of carbon steel and carbon steel; dissimilar metal welds for penetrations (containment - spares, access manholes, inspection ports), penetrations (containment electrical), penetrations (drywell mechanical), penetrations (drywell mechanical - flued heads, bellows), penetrations (torus mechanical), penetration sleeves, steel elements: drywell - shell, head, embedded and sandpocket regions (accessible and inaccessible areas), exposed to air - indoor uncontrolled in the Primary Containment. See Subsection 3.5.2.2.1.3.1. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.
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 Used. Loss of material for these components are managed under Item Numbers 3.5.1-006, 3.5.1-007, and 3.5.1-035.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage loss of material of stainless steel; bolting (containment closure), penetration (drywell mechanical), penetration (drywell mechanical flued heads, bellows), penetration (torus mechanical), and penetration sleeves exposed to air - indoor uncontrolled and treated water in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.
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	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.6.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-039	Steel elements: vent line bellows	Cracking due to SCC	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	Yes	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.1.31) and ASME Section XI, Subsection IWE (B.2.1.29) program will be used to manage cracking of stainless steel, steel elements: vent line, header, deflector, and bellows exposed to air - indoor uncontrolled in the Primary Containment. See Subsection 3.5.2.2.1.6. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B.2.1.29) program implementation.
3.5.1-040	Unbraced downcomers, steel elements: vent header; downcomers	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, "ASME Section XI, Subsection IWE"	Yes	Not Applicable. NMP1 is a Mark I steel containment. See Subsection 3.5.2.2.1.5.
3.5.1-041	Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt	None	None	No	Consistent with NUREG-2191.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-042	Groups 1-3, 5, 7-9: concrete (inaccessible areas): foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material (spalling, scaling) and cracking for inaccessible areas for concrete foundations, concrete above-grade exterior, concrete below-grade exterior, and duct banks, exposed to air – outdoor and groundwater/soil environments in the Reactor Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. See Subsection 3.5.2.2.1.1. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
3.5.1-043	All Groups except Group 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage cracking of concrete: all (inaccessible areas) exposed to air - indoor uncontrolled, air - outdoor, groundwater/soil, and water – flowing environments in the Primary Containment, Reactor Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. See Subsection 3.5.2.2.1.2. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-044	All Groups: concrete: all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S6, "Structures Monitoring"	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage cracking and distortion of concrete: all exposed to groundwater/soil in the Yard Structures. See Subsection 3.5.2.2.1.3. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
3.5.1-045	This item number is not listed in NUREG-2192.				
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	Not Used. The aging effects due to settlement are managed under Item Number 3.5.1-044. See Subsection 3.5.2.2.1.3.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage increase in porosity and permeability and loss of strength of inaccessible concrete areas for concrete foundations, concrete below-grade exterior, and duct banks, exposed to the water – flowing environment in the Reactor Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. See Subsection 3.5.2.2.2.1.4. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
3.5.1-048	Groups 1-5: concrete: all	Reduction of strength and modulus due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Not Applicable. See Subsection 3.5.2.2.2.2.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-049	Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material (spalling, scaling) and cracking of inaccessible concrete areas for above-grade exterior, below-grade exterior, basement, and foundations, exposed to air - outdoor and groundwater/soil environments in the Screen and Pump House Building. See Subsection 3.5.2.2.3.1. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
3.5.1-050	Groups 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage cracking of all the inaccessible concrete area exposed to air - indoor uncontrolled, air - outdoor, groundwater/soil, and water - flowing environments in the Screen and Pump House Building. See Subsection 3.5.2.2.3.2. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage increase in porosity and permeability and loss of strength of inaccessible concrete areas for above-grade exterior, basemat, foundation, below-grade exterior, interior, and tunnel (intake and discharge tunnels and structures) exposed to the water – flowing environment in the Screen and Pump House Building. See Subsection 3.5.2.2.2.3.3. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
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	Not Applicable. See Subsection 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, TLAA	Not Applicable See Subsection 3.5.2.2.2.5.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage cracking of all the accessible concrete exposed to air - indoor uncontrolled, air - outdoor, and water – flowing environments in the Primary Containment, Reactor Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage reduction in concrete anchor capacity of concrete for supports of ASME Class 1, 2, 3, and MC piping and components, supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components, supports for emergency diesel generator, HVAC system components, and other misc. mechanical equipment, supports for platforms, jet impingement shields, masonry walls, and other misc., supports for racks, panels, cabinets, and enclosures for electrical equipment and instrumentation exposed to air - indoor uncontrolled and air – outdoor environments in the Component Supports Commodity. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-056	Concrete: exterior above- and below- grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191 with exceptions. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program will be used to manage loss of material of concrete areas including curbs, basemat, foundation (accessible and inaccessible areas), below-grade exterior (inaccessible areas), interior (accessible and inaccessible areas), equipment supports and foundations, and tunnel (intake and discharge tunnels and structures) exposed to water - flowing in the Screen and Pump House Building. Exceptions apply to the NUREG-2191 recommendations for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program implementation.
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. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage loss of mechanical function of carbon steel supports for ASME Class 1, 2, 3, and MC piping and components exposed to air - indoor uncontrolled environment in the Component Supports Commodity.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program will be used to manage loss of material; loss of form of the soil, rip-rap, gravel, rock for structural miscellaneous (Unit 1 rock dike and applicable portion of the Unit 2 revetment-ditch system) exposed to air - outdoor and water - flowing environments in the Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) of the accessible concrete including curbs, above-grade exterior, basemat, foundation, interior, and equipment supports and foundations exposed to air - indoor uncontrolled, air - outdoor, and water - flowing environments in the Screen and Pump House Building. Exceptions apply to the NUREG-2191 recommendations for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program implementation.
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 with exceptions. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program will be used to manage loss of material (spalling, scaling) and cracking of the concrete: above-grade exterior (accessible areas) exposed to air - outdoor in the Screen and Pump House Building. Exceptions apply to the NUREG-2191 recommendations for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 with exceptions. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program will be used to manage increase in porosity and permeability, loss of strength of accessible concrete including curbs, above-grade exterior, basemat, foundation, interior, and equipment supports and foundations exposed to water - flowing in the Screen and Pump House Building. Exceptions apply to the NUREG-2191 recommendations for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program implementation.
3.5.1-062	Group 6: Wooden Piles; sheeting	Loss of material; change in material properties due to weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not Applicable.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage increase in porosity and permeability, loss of strength of the accessible concrete including above-grade exterior, foundation exposed to water - flowing in the Reactor Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material (spalling, scaling) and cracking of accessible concrete including above-grade exterior, foundation, interior exposed to air - outdoor in the Reactor Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) of the inaccessible concrete including, above-grade exterior, concrete: basemat, foundation, interior (including drywell floor and reactor pedestal), and duct banks exposed to air - indoor uncontrolled, air - outdoor, and groundwater/soil environments in the Primary Containment, Reactor Building, Screen and Pump House Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage cracking, loss of bond, and loss of material (spalling, scaling) of the accessible concrete areas including curbs, above-grade exterior, foundation, interior, near reactor vessel (reactor shield wall), equipment supports and foundations, hatches/plugs exposed to air - indoor uncontrolled, and air – outdoor environments in the Primary Containment, Reactor Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage increase in porosity and permeability, cracking, loss of material (spalling, scaling) of accessible concrete areas including above-grade exterior and interior; and of inaccessible concrete areas including basemat, foundation, below-grade exterior, interior (including drywell floor and reactor pedestal), and duct banks exposed to air - indoor uncontrolled, air – outdoor, and groundwater/soil environments in the Primary Containment, Reactor Building, Screen and Pump House Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
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. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage cracking of the high strength low alloy steel bolting with yield strength of 150 ksi or greater for supports for ASME Class 1 piping and components exposed to air - indoor uncontrolled in the Component Supports Commodity.
3.5.1-069	This Item Number is not listed in NUREG-2192.				

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Masonry Walls (B.2.1.32) program will be used to manage cracking of interior concrete block masonry walls exposed to air - indoor uncontrolled in the Reactor Building, Screen and Pump House Building, Turbine, Waste Handling, and Admin. Structures. Exceptions apply to the NUREG-2191 recommendations for the Masonry Walls (B.2.1.32) program implementation.
3.5.1-071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S5, "Masonry Walls"	No	Not Applicable. NMP1 does not have any in-scope masonry walls exposed to an air outdoor environment.
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of sealing of elastomers for expansion joints, roofing, seals, gaskets, and moisture barriers (caulking, flashing, and other sealants) exposed to the air - indoor uncontrolled and air - outdoor environments in the Structural Commodity Group. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Used. This component, material, environment, and aging effect combination is addressed by Item Number 3.5.1-034.
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of mechanical function of lubrite for supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components: sliding support bearings; sliding support surfaces exposed to air - indoor uncontrolled in the Component Supports Commodity. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
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. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage loss of mechanical function of lubrite for sliding surfaces of supports for ASME Class 1, 2, 3, and MC piping and components exposed to air - indoor uncontrolled in the Component Supports Commodity.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of mechanical function of lubrite sliding surfaces (drywell radial beam seats) exposed to air - indoor uncontrolled in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material of carbon steel and galvanized steel for concrete elements (curbs and embedments), equipment supports and foundations, hatches/plugs, jet impingement shields, steel components (structural steel, gates, ring girder for the reactor vessel support skirt, stabilizers, liner, liner anchors, integral attachments), , structural miscellaneous (siding, blowoff panels, sheet piles, floor plate, cover plates, valve pit cover), and trash racks exposed to air - indoor uncontrolled and air - outdoor environments in the Primary Containment, Reactor Building, Screen and Pump House Building, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Water Chemistry (B.2.1.2) program will be used to manage loss of material of stainless steel for steel elements: liner, liner anchors, integral attachments (spent fuel pool, reactor cavity, reactor internals storage pit, and transfer canal liners) exposed to Treated Water in the Reactor Building. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program implementation.
3.5.1-079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Not Applicable.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material of carbon and low alloy steel bolting and galvanized bolting for bolting (structural), concrete elements: anchors, supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components, supports for emergency diesel generator, HVAC system components, and other Misc. mechanical equipment, supports for platforms, jet impingement shields, masonry walls, and other misc. structures, supports for racks, panels, cabinets, and enclosures for electrical equipment and instrumentation exposed to air - indoor uncontrolled and air - outdoor environments in the Component Supports Commodity, Primary Containment, Reactor Building, Structural Commodity Group, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage loss of material of carbon and low alloy steel bolting and high strength low alloy steel bolting with yield strength of 150 ksi or greater for supports for ASME Class 1, 2, 3, and MC piping and components exposed to air - indoor uncontrolled environment in the Component Supports Commodity.
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material of galvanized bolting for bolting (structural) and concrete elements: anchors exposed to air - outdoor in the Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 with exceptions. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program will be used to manage loss of material of carbon and low alloy steel bolting, carbon steel, cast iron, and galvanized steel for bolting (structural), concrete elements: anchors, equipment supports and foundations, hatches/plugs, steel components (gates, structural steel), structural miscellaneous (sheet piles, floor plates, cover plates), and trash racks exposed to air - indoor uncontrolled, raw water, and water - flowing environments in the Screen and Pump House Building. Exceptions apply to the NUREG-2191 recommendations for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program implementation.
3.5.1-084	This Item Number is not listed in NUREG-2192.				

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWF (B.2.1.30) and Water Chemistry (B.2.1.2) program will be used to manage loss of material of stainless steel bolting for bolting (structural), bolting for supports for ASME Class 2, 3, and MC piping and components, and support anchorage to building structure exposed to treated water in Component Supports Commodity. Exceptions apply to the NUREG-2191 recommendations for the Water Chemistry (B.2.1.2) program implementation.
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. There is no structural bolting for supports of ASME Class 1, 2, 3, and MC piping and components exposed to air – outdoor.
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. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage loss of preload of carbon and low alloy steel bolting, high strength low alloy steel bolting with yield strength of 150 ksi or greater, and stainless steel bolting for supports for ASME Class 1, 2, 3, and MC piping and components exposed to air - indoor uncontrolled, and treated water environments in the Component Supports Commodity.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of preload of carbon and low alloy steel bolting, galvanized bolting, and stainless steel bolting for bolting (structural), concrete elements: anchors, supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components, supports for emergency diesel generator, HVAC system components, and other misc. mechanical equipment, supports for platforms, jet impingement shields, masonry walls, and other misc. structures, supports for racks, panels, cabinets, and enclosures for electrical equipment and instrumentation exposed to air - indoor uncontrolled, air - outdoor, raw water, treated water, and water - flowing environments in the Component Supports Commodity, Primary Containment, Reactor Building, Screen and Pump House Building, Structural Commodity Group, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-088 continued					The Inspection of Overhead Heavy Load and Light Load Related to Refueling Handling Systems (B.2.1.13) program has been substituted and will be used to manage loss of preload of stainless steel bolting for bolting (structural) exposed to air – indoor uncontrolled and treated water environments in the Cranes, Hoists, and Refueling Equipment System.
3.5.1-089	PWRs Only				
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	Consistent with NUREG-2191 with exceptions. The ASME Section XI, Subsection IWF (B.2.1.30) and Water Chemistry (B.2.1.2) program will be used to manage loss of material of carbon and low alloy steel bolting, carbon steel, and stainless steel for supports for ASME Class 2, 3, and MC piping and components exposed to treated water in the Component Supports Commodity. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B.2.1.2) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage loss of material of carbon steel for supports for ASME Class 1, 2, 3, and MC piping and components exposed to the air - indoor uncontrolled environment in the Component Supports Commodity.
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 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material of carbon steel for doors, panels, racks, frames, cabinets, and other enclosures, penetration sleeves, roofing, structural miscellaneous, supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components, supports for emergency diesel generator, HVAC system components, and other misc. mechanical equipment, supports for platforms, jet impingement shields, masonry walls, and other misc. structures, supports for racks, panels, cabinets, and enclosures for electrical equipment and instrumentation, and tube tracks exposed to air - indoor uncontrolled and air - outdoor environments in the Component Supports Commodity and Structural Commodity Group. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-093	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage loss of material of galvanized steel for cable trays and gutters, conduit, doors, and structural miscellaneous (catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, vents, etc.) exposed to air - outdoor in the Structural Commodity Group and Turbine, Waste Handling, and Admin. Structures. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation.
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	Not Applicable.
3.5.1-095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Consistent with NUREG-2191.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 with exceptions. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program will be used to manage cracking of all accessible areas of concrete exposed to air - indoor uncontrolled, air - outdoor, and water - flowing environments in the Screen and Pump House Building. Exceptions apply to the NUREG-2191 recommendations for the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program implementation.
3.5.1-097	Group 4: Concrete (reactor cavity area proximate to the reactor vessel): reactor (primary/biological) shield wall; sacrificial shield wall; reactor vessel support/pedestal structure	Reduction of strength; loss of mechanical properties due to irradiation (i.e., radiation interactions with material and radiation-induced heating)	Plant-specific aging management program or plant-specific enhancements to selected AMPs	Yes	Consistent with NUREG-2191 with exceptions. The Structures Monitoring (B.2.1.33) program will be used to manage reduction of strength and loss of mechanical properties of concrete: interior (accessible and inaccessible areas - drywell floor and reactor pedestal), and concrete: near reactor vessel (reactor shield wall) exposed to air - indoor uncontrolled in the Primary Containment. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) program implementation. See Subsection 3.5.2.2.2.6.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-098	Stainless steel, aluminum alloy support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not Applicable. There are no stainless steel or aluminum alloy support members, welds, bolted connections, or support anchorage to building structure exposed to air with borated water in the scope of license renewal.
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	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage loss of material and cracking of stainless steel and stainless steel bolting for supports of ASME Class 1, 2, 3, and MC piping and components exposed to air - indoor uncontrolled in the Component Supports Commodity. See Subsection 3.5.2.2.2.4.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The One-Time Inspection (B.2.1.20), and Structures Monitoring (B.2.1.33) programs will be used to manage loss of material and cracking of aluminum, stainless steel, stainless steel (mirror insulation), and stainless steel bolting for bolting (containment closure), bolting (structural), concrete elements (anchors), fuel storage racks (new fuel storage racks), insulation jacketing (thermal), panels, racks, frames, cabinets, and other enclosures, spent fuel pool gates, steel components, steel elements, structural miscellaneous, supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing, non-ASME piping and components, supports for emergency diesel generator, HVAC system components, and other misc. mechanical equipment, supports for platforms, jet impingement shields, masonry walls, and other misc. structures, supports for racks, panels, cabinets, and enclosures for electrical equipment and instrumentation exposed to air - indoor uncontrolled and air - outdoor environments in the Component Supports Commodity, Primary Containment, Reactor Building, Screen and Pump House Building, Structural Commodity Group, Turbine, Waste Handling, and Admin. Structures, and Yard Structures. See Subsection 3.5.2.2.2.4.

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-100 continued					The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) has been substituted and will be used to manage loss of material and cracking of aluminum alloy and stainless steel bolting for bolting (structural) and the crane and hoist for fuel prep machine exposed to the air – indoor uncontrolled environment in the Cranes, Hoists, and Refueling Equipment System. The fuel prep machine and refueling seal platform covers are constructed of 6061-T6 aluminum alloy which is not susceptible to stress corrosion cracking. Exceptions apply to the NUREG-2191 recommendations for the Structures Monitoring (B.2.1.33) and One-Time Inspection (B.2.1.20) program implementations.
3.5.1-101	Wooden Poles	Loss of material; changes in material properties due to weathering, chemical degradation, insect infestation, repeated wetting and drying, fungal decay	Plant-specific aging management program, or AMP XI.S6, "Structures Monitoring," enhanced as necessary	Yes	Not Applicable. See Section 3.5.2.2.2.7

Table 3.5.1 Summary of Aging Management Evaluations for the Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5.1-102	Reactor vessel steel structural supports, their assembled components (e.g., reactor vessel steel support skirt assembly; reactor vessel support girders/columns structure; neutron shield tank; reactor vessel support sliding feet assembly; reactor vessel seismic restraints; welds; bolted connections; support anchorage to building structure)	Reduction in fracture toughness, cracking, and/or loss of intended function (mechanical/ structural) due to irradiation induced combined mechanisms	Plant-specific aging management program, or plant-specific enhancements to selected GALL-SLR AMPs (e.g., AMP XI.S3, "ASME Section XI, Subsection IWF," and/or AMP XI.S6, "Structures Monitoring," and if/when necessary*, AMP XI.M1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD) * i.e., when there is evidence of combined aging effects associated with radiation exposure in areas of high tensile stresses	Yes	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.1.30) program will be used to manage reduction in fracture toughness of carbon steel supports for ASME Class 1 piping and components (including the reactor vessel to reactor shield wall stabilizers) exposed to air - indoor uncontrolled in Component Support Commodity. See Section 3.5.2.2.2.8
3.5.1-103	Reactor vessel support sliding surfaces, other special components (e.g., special coatings)	Loss of intended function (mechanical) due to irradiation	Plant-specific aging management program or plant-specific enhancement to selected GALL-SLR AMPs	Yes	Not Applicable. See Section 3.5.2.2.2.8

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35767	Supports for ASME Class 1 piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B1.1.TP-42	3.5.1-055	B
34611	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-226	3.5.1-081	A
34612	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5.1-087	A
34610	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-24	3.5.1-091	C
35782	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-28	3.5.1-057	A
34616	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A
34615	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A
35794	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A
35793	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A
35792	Supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5.1-087	A
38010	Supports for ASME Class 1 piping and components: sliding surfaces	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-24	3.5.1-091	C
38009	Supports for ASME Class 1 piping and components: sliding surfaces	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-28	3.5.1-057	C, 1
34617	Supports for ASME Class 1 piping and components: sliding surfaces	Structural Support	Lubrite	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-45	3.5.1-075	A

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39059	Supports for ASME Class 1 piping and components: stabilizers (reactor vessel to reactor shield wall)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-24	3.5.1-091	A
39060	Supports for ASME Class 1 piping and components: stabilizers (reactor vessel to reactor shield wall)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Reduction in Fracture Toughness	ASME Section XI, Subsection IWF (B.2.1.30)	III.A4.T-36	3.5.1-102	A
34624	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-226	3.5.1-081	A
34623	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5.1-087	A
34620	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-24	3.5.1-091	A
35877	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-41	3.5.1-068	A
35876	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-226	3.5.1-081	A
35878	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5.1-087	A
34622	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34621	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A
34627	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A
34626	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-36b	3.5.1-099	A
34625	Supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5.1-087	A
35769	Supports for ASME Class 2 and 3 piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B1.2.TP-42	3.5.1-055	B
34630	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-226	3.5.1-081	A
34629	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A
38939	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5.1-090	A
48939	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	B
38940	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Treated Water	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A
34628	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-24	3.5.1-091	C

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35783	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-28	3.5.1-057	A
38938	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5.1-090	A
48938	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	B
34632	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
34631	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
35846	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5.1-090	C
45846	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	D
34635	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
34634	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
34633	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A
34642	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-232	3.5.1-085	A
44642	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.2.TP-232	3.5.1-085	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34641	Supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A
38011	Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-24	3.5.1-091	C
38008	Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-28	3.5.1-057	C, 2
34688	Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Lubrite	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-45	3.5.1-075	A
38014	Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
38013	Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
38012	Supports for ASME Class 2 and 3 piping and components: sliding surfaces	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)			F, 2
34703	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-226	3.5.1-081	A
34702	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A
38942	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5.1-090	A
48942	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	B
38943	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Treated Water	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34699	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-24	3.5.1-091	A
38941	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5.1-090	A
48941	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	B
34707	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
34706	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
35847	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5.1-090	C
45847	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	D
34710	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
34709	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-36b	3.5.1-099	A
34708	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34712	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-232	3.5.1-085	A
44712	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.2.TP-232	3.5.1-085	B
34711	Supports for ASME Class 2 and 3 piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5.1-087	A
35770	Supports for ASME Class MC piping and components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B1.3.TP-42	3.5.1-055	B
34741	Supports for ASME Class MC piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-226	3.5.1-081	A
34740	Supports for ASME Class MC piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5.1-087	A
34737	Supports for ASME Class MC piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-24	3.5.1-091	C
35786	Supports for ASME Class MC piping and components: constant and variable load spring hangers; guides; stops	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-28	3.5.1-057	A
34691	Supports for ASME Class MC piping and components: sliding surfaces	Structural Support	Lubrite	Air - Indoor, Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-45	3.5.1-075	A
34719	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-226	3.5.1-081	A
34718	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5.1-087	A

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34715	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-24	3.5.1-091	C
34722	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-36b	3.5.1-099	A
34723	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-36b	3.5.1-099	A
35848	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5.1-090	C
45848	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.1.TP-10	3.5.1-090	D
34726	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-36b	3.5.1-099	A
34725	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-36b	3.5.1-099	A
34724	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5.1-087	A
34728	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-232	3.5.1-085	A
44728	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.B1.3.TP-232	3.5.1-085	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34727	Supports for ASME Class MC piping and components: support member; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Preload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5.1-087	A
35771	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5.1-055	B
35851	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5.1-055	B
34748	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: sliding support bearings; sliding support surfaces	Structural Support	Lubrite	Air - Indoor, Uncontrolled	Loss of Mechanical Function	Structures Monitoring (B.2.1.33)	III.B2.TP-46	3.5.1-074	B
34753	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5.1-080	B
34752	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5.1-088	B
35958	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5.1-080	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35957	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5.1-088	B
34749	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5.1-092	B
35862	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5.1-092	B
35907	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B
35908	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B
35909	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35910	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B
35897	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B
35896	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B
35895	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5.1-088	B
35900	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B
35901	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.T-37b	3.5.1-100	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35902	Supports for Cable Trays, Conduit, HVAC Ducts, Tube Track, Instrument Tubing, Non-ASME Piping and Components: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5.1-088	B
35773	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5.1-055	B
35855	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5.1-055	B
35916	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5.1-080	B
35915	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5.1-088	B
35960	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5.1-080	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35959	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5.1-088	B
35913	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	B
35914	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	B
35917	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
35918	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
35919	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35920	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
35923	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
35922	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
35921	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5.1-088	B
35924	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
35925	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35926	Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5.1-088	B
35774	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B5.TP-42	3.5.1-055	B
35858	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B5.TP-42	3.5.1-055	B
35932	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5.1-080	B
35931	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5.1-088	B
35962	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5.1-080	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35961	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5.1-088	B
35929	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.TP-43	3.5.1-092	B
35930	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.TP-43	3.5.1-092	B
35939	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
35940	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
35941	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35942	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
35935	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
35934	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
35933	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5.1-088	B
35936	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
35937	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35938	Supports for Platforms, Pipe Whip Restraints, Jet Impingement Shields, Masonry Walls, and Other Misc. Structures: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5.1-088	B
35775	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B3.TP-42	3.5.1-055	B
35859	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Reinforced concrete	Air - Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.1.33)	III.B3.TP-42	3.5.1-055	B
35946	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.TP-248	3.5.1-080	B
35945	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5.1-088	B
35965	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.TP-248	3.5.1-080	B
35964	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5.1-088	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35943	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.TP-43	3.5.1-092	B
35944	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.TP-43	3.5.1-092	B
35953	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B
35954	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B
35955	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B
35956	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B
35949	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B
35948	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35947	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5.1-088	B
35950	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B
35951	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	B
35952	Supports for Racks, Panels, Cabinets, and Enclosures for Electrical Equipment and Instrumentation: support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5.1-088	B

Table 3.5.2-1 Component Supports Commodity Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The stabilizer at the top of the reactor vessel allows for movement and does not use Lubrite or similar material but instead consists of steel to steel connections.
2. Support designs allow for movements and do not use Lubrite or similar material but instead consist of steel to steel or stainless steel to stainless steel connections.

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34860	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-148	3.5.1-031	B
34861	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-150	3.5.1-030	A
44861	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-150	3.5.1-030	B
34864	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking, Loss of Material	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5.1-100	B
36616	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.2.C-49	3.5.1-037	C
46616	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.2.C-49	3.5.1-037	D
35086	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-150	3.5.1-030	A
45086	Bolting (Containment Closure)	Structural Pressure Barrier, Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-150	3.5.1-030	B
34865	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-248	3.5.1-080	B, 1
35085	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5.1-088	B, 1
34870	Bolting (Structural)	Structural Support	Galvanized Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-248	3.5.1-080	B
34871	Bolting (Structural)	Structural Support	Galvanized Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5.1-088	B
34872	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-248	3.5.1-080	B
34873	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5.1-088	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35022	Concrete Elements: Embedments	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5.1-077	B
36574	Concrete: All (accessible areas)	Direct Flow, HELB/MELB Shielding, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A4.TP-25	3.5.1-054	B
36575	Concrete: All (inaccessible areas)	Direct Flow, HELB/MELB Shielding, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A4.TP-204	3.5.1-043	B
35393	Concrete: Interior (accessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A4.TP-26	3.5.1-066	B
39186	Concrete: Interior (accessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A4.TP-28	3.5.1-067	B
39065	Concrete: Interior (accessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction of Strength; Loss of Mechanical Properties	Structures Monitoring (B.2.1.33)	III.A4.T-35	3.5.1-097	B, 2
35396	Concrete: Interior (inaccessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
39199	Concrete: Interior (inaccessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A4.TP-28	3.5.1-067	B
39064	Concrete: Interior (inaccessible areas - drywell floor and reactor pedestal)	Direct Flow, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction of Strength; Loss of Mechanical Properties	Structures Monitoring (B.2.1.33)	III.A4.T-35	3.5.1-097	B, 2
35405	Concrete: near reactor vessel (reactor shield wall)	Direct Flow, HELB/MELB Shielding, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A4.TP-26	3.5.1-066	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35406	Concrete: near reactor vessel (reactor shield wall)	Direct Flow, HELB/MELB Shielding, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Reduction of Strength; Loss of Mechanical Properties	Structures Monitoring (B.2.1.33)	III.A4.T-35	3.5.1-097	B, 2
35435	Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A4.TP-26	3.5.1-066	B
35739	Moisture barriers (caulking, flashing and other sealants)	Shelter/Protection, Water Retaining Boundary	Elastomers	Air - Indoor, Uncontrolled	Loss of Sealing	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-40	3.5.1-026	B
35761	Penetration - Containment - spares, access manholes, inspection ports	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
45761	Penetration - Containment - spares, access manholes, inspection ports	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
35762	Penetration - Containment - spares, access manholes, inspection ports	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A
45762	Penetration - Containment - spares, access manholes, inspection ports	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B
36508	Penetration - Containment Electrical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
46508	Penetration - Containment Electrical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35982	Penetration - Containment Electrical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A
45982	Penetration - Containment Electrical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B
36013	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
46013	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
36014	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A
46014	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36015	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
46015	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
36016	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A
46016	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B
36021	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
46021	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36027	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.2.C-49	3.5.1-037	C
46027	Penetration - Drywell Mechanical	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.2.C-49	3.5.1-037	D
38433	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-38	3.5.1-010	A
36017	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
38433	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-38	3.5.1-010	B
36017	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
38383	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TAA	II.B4.C-13	3.5.1-009	A, 3
36018	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A
46018	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Carbon Steel; dissimilar metal welds	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B
36026	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
38434	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Stainless Steel	Air - Indoor, Uncontrolled	cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-38	3.5.1-010	A

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36026	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
38434	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Stainless Steel	Air - Indoor, Uncontrolled	cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-38	3.5.1-010	B
38382	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Stainless Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 3, 4
36025	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.2.C-49	3.5.1-037	C, 4
46025	Penetration - Drywell Mechanical (flued heads, bellows)	Expansion/Separation	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.2.C-49	3.5.1-037	D, 4
36019	Penetration - Drywell Mechanical (flued heads, bellows)	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
46019	Penetration - Drywell Mechanical (flued heads, bellows)	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
36020	Penetration - Drywell Mechanical (flued heads, bellows)	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A
6020	Penetration - Drywell Mechanical (flued heads, bellows)	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B
35985	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 3
35984	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
45984	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B
36022	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-109	3.5.1-007	D
38317	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.2.C-49	3.5.1-037	C
48317	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.2.C-49	3.5.1-037	D
38318	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Stainless Steel	Treated Water	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.2.C-49	3.5.1-037	C
48318	Penetration - Torus Mechanical	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Stainless Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.2.C-49	3.5.1-037	D
35750	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
45750	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36611	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B4.C-13	3.5.1-009	A, 3
35751	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5.1-035	A
45751	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-36	3.5.1-035	B
35755	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
45755	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
36024	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.2.C-49	3.5.1-037	C
46024	Penetration Sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.2.C-49	3.5.1-037	D
35738	Personnel airlock, drywell emergency airlock, equipment hatch	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	A
45738	Personnel airlock, drywell emergency airlock, equipment hatch	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	B
35664	Personnel airlock, drywell emergency airlock, equipment hatch	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.C-16	3.5.1-028	A

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
45664	Personnel airlock, drywell emergency airlock, equipment hatch	Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.C-16	3.5.1-028	B
35737	Personnel airlock, drywell emergency airlock: locks, hinges, and closure mechanisms	Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Leaktightness	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-39	3.5.1-029	A
45737	Personnel airlock, drywell emergency airlock: locks, hinges, and closure mechanisms	Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Leaktightness	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-39	3.5.1-029	B
36035	Pipe Whip Restraints and Jet Impingement Shields	Direct Flow, HELB/MELB Shielding, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5.1-077	B
35740	Seals and gaskets	Shelter/Protection	Elastomers	Air - Indoor, Uncontrolled	Loss of Sealing	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-41	3.5.1-033	A
36036	Service Level I Coatings	Maintain Adhesion	Coatings	Air - Indoor, Uncontrolled	Loss of Coating or Lining Integrity	Protective Coating Monitoring and Maintenance (B.2.1.35)	II.B4.CP-152	3.5.1-034	A
36037	Service Level I Coatings	Maintain Adhesion	Coatings	Treated Water	Loss of Coating or Lining Integrity	Protective Coating Monitoring and Maintenance (B.2.1.35)	II.B4.CP-152	3.5.1-034	A
35162	Sliding Surfaces (drywell radial beam seats)	Structural Support	Lubrite	Air - Indoor, Uncontrolled	Loss of Mechanical Function	Structures Monitoring (B.2.1.33)	III.A4.TP-35	3.5.1-076	B
35592	Steel Components: Ring Girder for the Reactor Vessel Support Skirt	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5.1-077	B
39066	Steel Components: Stabilizers (truss arrangements between reactor shield wall to drywell)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5.1-077	B
35589	Steel Components: structural steel	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5.1-077	B
35056	Steel Components: structural steel (refueling seal platform)	Structural Support, Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5.1-077	B, 1
36470	Steel Components: structural steel (refueling seal platform)	Structural Support, Water Retaining Boundary	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D, 1

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36581	Steel elements: Downcomers	Direct Flow, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 3
36580	Steel elements: Downcomers	Direct Flow, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-109	3.5.1-007	B
36582	Steel elements: Downcomers	Direct Flow, Structural Support	Carbon Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-109	3.5.1-007	B
36509	Steel elements: Drywell - shell, head, embedded and sandpocket regions (accessible areas)	HELB/MELB Shielding, Missile Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	C
46509	Steel elements: Drywell - shell, head, embedded and sandpocket regions (accessible areas)	HELB/MELB Shielding, Missile Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	D
36039	Steel elements: Drywell - shell, head, embedded and sandpocket regions (accessible areas)	HELB/MELB Shielding, Missile Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-43	3.5.1-035	A
46039	Steel elements: Drywell - shell, head, embedded and sandpocket regions (accessible areas)	HELB/MELB Shielding, Missile Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-43	3.5.1-035	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36510	Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-37	3.5.1-027	C
46510	Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-37	3.5.1-027	D
36040	Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-43	3.5.1-035	C
46040	Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-43	3.5.1-035	D
36041	Steel elements: Drywell - shell, head, embedded and sandpocket regions (inaccessible areas)	HELB/MELB Shielding, Shelter/Protection, Structural Pressure Barrier, Structural Support	Carbon Steel	Concrete	None	None	II.B1.1.CP-44	3.5.1-041	A
36038	Steel elements: Drywell - support skirt (inaccessible areas)	Structural Support	Carbon Steel	Concrete	None	None	II.B1.1.CP-44	3.5.1-041	A
36028	Steel Elements: liner, liner anchors, integral attachments (reactor pedestal and reactor shield wall)	Direct Flow, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5.1-077	B
35053	Steel elements: Refueling Bellows assemblies	Expansion/Separation, Water Retaining Boundary	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5.1-100	D, 1, 5

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35027	Steel elements: Torus shell, ring girders	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 3
36032	Steel elements: Torus shell, ring girders	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-48	3.5.1-006	A
46032	Steel elements: Torus shell, ring girders	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-48	3.5.1-006	B
36031	Steel elements: Torus shell, ring girders	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Treated Water	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-48	3.5.1-006	A
46031	Steel elements: Torus shell, ring girders	Structural Pressure Barrier, Structural Support, Water Retaining Boundary	Carbon Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-48	3.5.1-006	B
35037	Steel elements: Vent line, header, deflector, bellows	Direct Flow, Expansion/Separation, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Cumulative Fatigue Damage	TLAA	II.B1.1.C-21	3.5.1-009	A, 3
36034	Steel elements: Vent line, header, deflector, bellows	Direct Flow, Expansion/Separation, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-48	3.5.1-006	A
46034	Steel elements: Vent line, header, deflector, bellows	Direct Flow, Expansion/Separation, Structural Pressure Barrier, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-48	3.5.1-006	B

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39194	Steel elements: Vent line, header, deflector, bellows	Expansion/Separation, Structural Pressure Barrier	Stainless Steel	Air - Indoor, Uncontrolled	cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-50	3.5.1-039	A
39195	Steel elements: Vent line, header, deflector, bellows	Expansion/Separation, Structural Pressure Barrier	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-49	3.5.1-027	A
39194	Steel elements: Vent line, header, deflector, bellows	Expansion/Separation, Structural Pressure Barrier	Stainless Steel	Air - Indoor, Uncontrolled	cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-50	3.5.1-039	B
39195	Steel elements: Vent line, header, deflector, bellows	Expansion/Separation, Structural Pressure Barrier	Stainless Steel	Air - Indoor, Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-49	3.5.1-027	B
35084	Structural Miscellaneous (refueling seal platform covers)	Water Retaining Boundary	Aluminum	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D, 1, 6

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The normal environment for this component is Air-indoor, Uncontrolled. The refueling seal platform, refueling seal platform covers, related fasteners, and associated bellows are exposed to treated water only when the reactor is in a cold shutdown condition and the reactor cavity is filled with water to support refueling operations. This environment has a short duration; therefore, it is not addressed separately for aging management.
2. The Structures Monitoring (B.2.1.33) program is used to manage the aging effects of reduction of strength and loss of mechanical properties due to irradiation for this component type, material, and environment combination.
3. The TLAA designation in the Aging Management Programs column indicates cumulative fatigue damage of this component is evaluated in SLRA Section 4.6.
4. Bellows for the Main Steam header drywell penetrations are constructed of Inconel Alloy 625, which is similar to stainless steel and is subject to the same aging effects.

Table 3.5.2-2 Primary Containment Summary of Aging Management Evaluation

5. This component is not in low-flow or stagnant areas since the area is drained upon completion of the refueling outage and heat from the reactor pressure vessel causes rapid evaporation of any moisture remaining in the bellows. Plant-specific operating experience reviews have not identified any failures or leakage from the refueling bellows.
6. This component is constructed of 6061-T6 aluminum alloy, which is not susceptible to stress corrosion cracking.

Table 3.5.2-3 Reactor Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33222	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-248	3.5.1-080	B
33224	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5.1-088	B
33223	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-248	3.5.1-080	B
33225	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5.1-088	B
33891	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
33345	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5.1-088	B
33361	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	VII.A2.A-98	3.3.1-125	D
33343	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Treated Water	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5.1-088	B
33278	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-248	3.5.1-080	B
33279	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5.1-088	B
33353	Concrete Elements: Curbs	Direct Flow	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5.1-077	B
37087	Concrete Elements: Curbs	Direct Flow	Concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5.1-066	B, 1
33296	Concrete Elements: Embedments	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5.1-077	B
34130	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5.1-066	B
39184	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Outdoor	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-28	3.5.1-067	B

Table 3.5.2-3 Reactor Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34122	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-23	3.5.1-064	B
34114	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A2.TP-24	3.5.1-063	B
33226	Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
34132	Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-108	3.5.1-042	D
33335	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5.1-054	B
34134	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5.1-054	B
35516	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5.1-054	B

Table 3.5.2-3 Reactor Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33336	Concrete: All (inaccessible areas)	Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5.1-043	B
34135	Concrete: All (inaccessible areas)	Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5.1-043	B
33337	Concrete: All (inaccessible areas)	Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5.1-043	B
33262	Concrete: All (inaccessible areas)	Flood Barrier, Shelter/Protection, Shielding, Structural Pressure Barrier, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5.1-043	B
33256	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-212	3.5.1-065	B
35517	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-29	3.5.1-067	B
33257	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-108	3.5.1-042	B

Table 3.5.2-3 Reactor Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33261	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5.1-047	B
33269	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-212	3.5.1-065	B
35518	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-29	3.5.1-067	B
33270	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A2.TP-108	3.5.1-042	B
33273	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5.1-047	B
33274	Concrete: Interior	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5.1-066	B
39185	Concrete: Interior	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-28	3.5.1-067	B
33301	Equipment supports and foundations	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5.1-077	B
33285	Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5.1-066	B
33297	Fuel Storage Racks (New Fuel Storage Racks)	Structural Support	Aluminum	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B

Table 3.5.2-3 Reactor Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33298	Fuel Storage Racks (New Fuel Storage Racks)	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	VII.A1.A-94	3.3.1-111	B
33896	Fuel Storage Racks (New Fuel Storage Racks)	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
33302	Hatches/Plugs	Shelter/Protection, Shielding	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5.1-077	B
33303	Hatches/Plugs	Shelter/Protection, Shielding	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5.1-066	B
33304	Masonry walls: Interior	Shelter/Protection, Shielding, Structural Support	Concrete Block	Air - Indoor, Uncontrolled	Cracking	Masonry Walls (B.2.1.32)	III.A2.T-12	3.5.1-070	B
33308	Spent fuel pool gates	Water Retaining Boundary	Aluminum	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
33293	Spent fuel pool gates	Water Retaining Boundary	Aluminum	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	VII.A4.AP-130	3.3.1-025	D
33892	Spent fuel pool gates	Water Retaining Boundary	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
33310	Steel Components: structural steel	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5.1-077	B
33893	Steel Elements: liner, liner anchors, integral attachments (Spent Fuel Pool, Reactor Cavity, Reactor Internals Storage Pit, and Transfer Canal Liners)	Water Retaining Boundary	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
39047	Steel Elements: liner, liner anchors, integral attachments (Spent Fuel Pool, Reactor Cavity, Reactor Internals Storage Pit, and Transfer Canal Liners)	Water Retaining Boundary	Stainless Steel	Treated Water	Cumulative Fatigue Damage	TLAA	II.B2.1.C-45	3.5.1-009	C, 2
33284	Steel Elements: liner, liner anchors, integral attachments (Spent Fuel Pool, Reactor Cavity, Reactor Internals Storage Pit, and Transfer Canal Liners)	Water Retaining Boundary	Stainless Steel	Treated Water	Loss of Material	Water Chemistry (B.2.1.2)	III.A5.T-14	3.5.1-078	B, 3
33360	Structural Miscellaneous - Siding	Shelter/Protection, Structural Pressure Barrier	Aluminum	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
33314	Structural Miscellaneous - Siding	Shelter/Protection, Structural Pressure Barrier	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5.1-077	B

Table 3.5.2-3 Reactor Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33359	Structural Miscellaneous - Siding (Blowoff Panels)	Pressure Relief, Shelter/Protection, Structural Pressure Barrier	Aluminum	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
33315	Structural Miscellaneous - Siding (Blowoff Panels)	Pressure Relief, Shelter/Protection, Structural Pressure Barrier	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5.1-077	B

Table 3.5.2-3 Reactor Building Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. Concrete curbs were poured without reinforcing steel. Instead, the curbs utilize carbon steel framing. Therefore, the aging effect/aging mechanism of Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel is not applicable.
2. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.6.
3. The spent fuel pool water level, leakage, and chemistry are monitored in accordance with station procedures.

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34060	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	B
34061	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34067	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	B
34068	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Water - Flowing	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34064	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
34066	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34076	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	VII.I.A-423	3.3.1-142	E, 1
34077	Bolting (Structural)	Structural Support	Stainless Steel Bolting	Raw Water	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34112	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	B
35123	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34071	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	B
34072	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Water - Flowing	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34073	Concrete Elements: Anchors	Structural Support	Galvanized Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34074	Concrete Elements: Anchors	Structural Support	Galvanized Bolting	Water - Flowing	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34845	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
34846	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
34848	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	VII.I.A-423	3.3.1-142	E, 1
34847	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Raw Water	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5.1-088	B
35161	Concrete Elements: Curbs	Direct Flow	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5.1-059	B
34079	Concrete Elements: Curbs	Direct Flow	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5.1-061	B
35163	Concrete Elements: Curbs	Direct Flow	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	D
34083	Concrete Elements: Embedments	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34300	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5.1-059	B
39182	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5.1-067	B
34301	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5.1-060	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34302	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5.1-061	B, 2
34313	Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
34314	Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5.1-049	B
39198	Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5.1-051	B, 2
34315	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5.1-096	B
34320	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5.1-096	B
34321	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5.1-096	B
34322	Concrete: All (inaccessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5.1-050	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34323	Concrete: All (inaccessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5.1-050	B
34324	Concrete: All (inaccessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5.1-050	B
34325	Concrete: All (inaccessible areas)	Direct Flow, Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5.1-050	B
34326	Concrete: Basemat, Foundation (accessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5.1-059	B
34327	Concrete: Basemat, Foundation (accessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5.1-061	B
34329	Concrete: Basemat, Foundation (accessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34334	Concrete: Basemat, Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
36224	Concrete: Basemat, Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-107	3.5.1-067	B
35160	Concrete: Basemat, Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5.1-049	B
34337	Concrete: Basemat, Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5.1-051	B
34338	Concrete: Basemat, Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	B
34339	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
36260	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-107	3.5.1-067	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36259	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5.1-049	B
34341	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5.1-051	B
34342	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	B
34343	Concrete: Interior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5.1-059	B
39183	Concrete: Interior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5.1-067	B
34344	Concrete: Interior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5.1-061	B
34345	Concrete: Interior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	B
34346	Concrete: Interior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
34347	Concrete: Interior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5.1-051	B
34353	Concrete: Interior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34363	Equipment supports and foundations	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34371	Equipment supports and foundations	Structural Support	Carbon Steel	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D
34354	Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5.1-059	B
34360	Equipment supports and foundations	Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5.1-061	B
34362	Equipment supports and foundations	Structural Support	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	B
34372	Hatches/Plugs	Shelter/Protection	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34373	Hatches/Plugs	Shelter/Protection	Carbon Steel	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D
34381	Masonry walls: Interior	Shelter/Protection, Structural Support	Concrete Block	Air - Indoor, Uncontrolled	Cracking	Masonry Walls (B.2.1.32)	III.A6.T-12	3.5.1-070	B
34392	Steel Components (Gates)	Water Retaining Boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34393	Steel Components (Gates)	Water Retaining Boundary	Carbon Steel	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D
35168	Steel Components (Gates)	Water Retaining Boundary	Cast Iron	Air - Indoor, Uncontrolled	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35165	Steel Components (Gates)	Water Retaining Boundary	Cast Iron	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D
35166	Steel Components (Gates)	Water Retaining Boundary	Cast Iron	Raw Water	Loss of Material/Selective Leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3.1-072	D
34849	Steel Components (Gates)	Water Retaining Boundary	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
34851	Steel Components (Gates)	Water Retaining Boundary	Stainless Steel	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 1
34408	Steel Components: structural steel	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34410	Steel Components: structural steel	Structural Support	Carbon Steel	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D
34672	Steel Components: structural steel	Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
34673	Steel Components: structural steel	Structural Support	Stainless Steel	Raw Water	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	VII.E5.A-413	3.3.1-137	E, 1
34426	Structural Miscellaneous - Siding	Shelter/Protection	Aluminum	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
34418	Structural Miscellaneous (Sheet Piles, Floor Plate, Cover Plates)	Shelter/Protection	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34420	Structural Miscellaneous (Sheet Piles, Floor Plate, Cover Plates)	Shelter/Protection	Carbon Steel	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D
34431	Trash Racks	Filter	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34432	Trash Racks	Filter	Carbon Steel	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5.1-083	D
34438	Tunnel (Intake and Discharge Tunnels and Structures)	Direct Flow, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5.1-051	B
34439	Tunnel (Intake and Discharge Tunnels and Structures)	Direct Flow, Shelter/Protection, Structural Support, Water Retaining Boundary	Reinforced concrete	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5.1-056	B

Table 3.5.2-4 Screen and Pump House Building Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The Inspection of Water Control Structures Associated with Nuclear Power Plants (B.2.1.34) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.
2. For above-grade concrete the environment of water-flowing is referring to rainwater.

Table 3.5.2-5 Structural Commodity Group Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33705	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
33706	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
33707	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
33708	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
33713	Cable Trays and Gutters	Shelter/Protection, Structural Support	Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
33711	Cable Trays and Gutters	Shelter/Protection, Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-6	3.5.1-093	D
33806	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
33807	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
33808	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
33809	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
33947	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
33804	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
33949	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	B
33805	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
33716	Conduit	Shelter/Protection, Structural Support	Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B2.TP-8	3.5.1-095	C
33717	Conduit	Shelter/Protection, Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-6	3.5.1-093	D

Table 3.5.2-5 Structural Commodity Group Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33812	Doors	Flood Barrier, HELB/MELB Shielding, Shelter/Protection, Shielding, Structural Pressure Barrier	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	D
33813	Doors	Flood Barrier, HELB/MELB Shielding, Shelter/Protection, Shielding, Structural Pressure Barrier	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	D
33724	Doors	Flood Barrier, HELB/MELB Shielding, Shelter/Protection, Shielding, Structural Pressure Barrier	Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B4.TP-8	3.5.1-095	C
33725	Doors	Flood Barrier, HELB/MELB Shielding, Shelter/Protection, Shielding, Structural Pressure Barrier	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-6	3.5.1-093	D
33456	Expansion Joints	Expansion/Separation	Elastomers	Air - Indoor, Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5.1-072	D
39187	Insulation - Thermal	Thermal Insulation	Asbestos	Air - Indoor, Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-403	3.4.1-064	A
39188	Insulation - Thermal	Thermal Insulation	Asbestos	Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-403	3.4.1-064	A
39189	Insulation - Thermal	Thermal Insulation	Calcium Silicate	Air - Indoor, Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-403	3.4.1-064	A

Table 3.5.2-5 Structural Commodity Group Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39190	Insulation - Thermal	Thermal Insulation	Calcium Silicate	Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-403	3.4.1-064	A
39191	Insulation - Thermal	Thermal Insulation	Fiberglass	Air - Indoor, Uncontrolled	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-403	3.4.1-064	A
39192	Insulation - Thermal	Thermal Insulation	Fiberglass	Air - Outdoor	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-403	3.4.1-064	A
33978	Insulation - Thermal	Thermal Insulation	Stainless Steel (Mirror Insulation)	Air - Indoor, Uncontrolled	Cracking, Loss of Material	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5.1-100	D
33701	Insulation Jacketing - Thermal	Thermal Insulation Jacket Integrity	Aluminum	Air - Indoor, Uncontrolled	Loss of Material	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5.1-100	D, 1
33702	Insulation Jacketing - Thermal	Thermal Insulation Jacket Integrity	Aluminum	Air - Outdoor	Loss of Material	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5.1-100	D, 1
33703	Insulation Jacketing - Thermal	Thermal Insulation Jacket Integrity	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5.1-100	D
33704	Insulation Jacketing - Thermal	Thermal Insulation Jacket Integrity	Stainless Steel	Air - Outdoor	Cracking, Loss of Material	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5.1-100	D
33819	Panels, Racks, Frames, Cabinets, and Other Enclosures	Shelter/Protection, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.TP-43	3.5.1-092	D
33820	Panels, Racks, Frames, Cabinets, and Other Enclosures	Shelter/Protection, Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.TP-43	3.5.1-092	D
33814	Panels, Racks, Frames, Cabinets, and Other Enclosures	Shelter/Protection, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	D
33818	Panels, Racks, Frames, Cabinets, and Other Enclosures	Shelter/Protection, Structural Support	Stainless Steel	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B3.T-37b	3.5.1-100	D
33821	Penetration sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support, Water retaining boundary	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	D
36392	Penetration sleeves	Shelter/Protection, Structural Pressure Barrier, Structural Support, Water retaining boundary	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	D

Table 3.5.2-5 Structural Commodity Group Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33822	Roofing	Shelter/Protection	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	D
36302	Roofing	Shelter/Protection	Elastomers	Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5.1-072	B
33730	Seals, gaskets, and moisture barriers (caulking, flashing and other sealants)	HELB/MELB Shielding, Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Water retaining boundary	Elastomers	Air - Indoor, Uncontrolled	Loss of Sealing	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5.1-072	B
33734	Seals, gaskets, and moisture barriers (caulking, flashing and other sealants)	HELB/MELB Shielding, Flood Barrier, Shelter/Protection, Structural Pressure Barrier, Water retaining boundary	Elastomers	Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5.1-072	B
33798	Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support	Aluminum	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	D
33801	Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support	Aluminum	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	D
33823	Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	D
33824	Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5.1-092	D
33729	Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support	Galvanized Steel	Air - Indoor, Uncontrolled	None	None	III.B4.TP-8	3.5.1-095	C
33728	Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.TP-6	3.5.1-093	D
36497	Structural Miscellaneous - catwalks, grating, handrails, kick plates, ladders, manhole covers, platforms, stairs, etc.	Shelter/Protection, Shielding, Structural Support	Stainless Steel	Air - Indoor, Uncontrolled	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B4.T-37b	3.5.1-100	D

Table 3.5.2-5 Structural Commodity Group Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
33720	Tube Track	Shelter/Protection, Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5.1-092	D

Table 3.5.2-5 Structural Commodity Group Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The aluminum jacketing is constructed of 1145, 3003, or 5005 aluminum alloys, which are not susceptible to stress corrosion cracking.

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34958	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
34959	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
39151	Bolting (Structural) (Stack)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A9.TP-248	3.5.1-080	B
39152	Bolting (Structural) (Stack)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A9.TP-261	3.5.1-088	B
34960	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
34961	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
39153	Concrete Elements: Anchors (Stack)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A9.TP-248	3.5.1-080	B
39154	Concrete Elements: Anchors (Stack)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A9.TP-261	3.5.1-088	B
34962	Concrete Elements: Curbs	Direct Flow	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
34963	Concrete Elements: Embedments	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34964	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
39179	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5.1-067	B
34965	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5.1-064	B
34966	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5.1-063	B

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39155	Concrete: Above-grade exterior (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A9.TP-26	3.5.1-066	B
39180	Concrete: Above-grade exterior (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A9.TP-28	3.5.1-067	B
39156	Concrete: Above-grade exterior (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-23	3.5.1-064	B
39157	Concrete: Above-grade exterior (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A9.TP-24	3.5.1-063	B
34967	Concrete: Above-grade exterior (inaccessible areas)	Gaseous Release Path, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
34968	Concrete: Above-grade exterior (inaccessible areas)	Gaseous Release Path, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5.1-042	B
39160	Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
39161	Concrete: Above-grade exterior (inaccessible areas)	Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5.1-042	B
39158	Concrete: Above-grade exterior (inaccessible areas) (Stack)	Gaseous Release Path, Shelter Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5.1-065	B
39159	Concrete: Above-grade exterior (inaccessible areas) (Stack)	Gaseous Release Path, Shelter Protection, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-108	3.5.1-042	B

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34655	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5.1-054	B
34656	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5.1-054	B
34658	Concrete: All (accessible areas)	Direct Flow, Flood Barrier, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5.1-054	B
39164	Concrete: All (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-25	3.5.1-054	B
39163	Concrete: All (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-25	3.5.1-054	B
39162	Concrete: All (accessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-25	3.5.1-054	B

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34651	Concrete: All (inaccessible areas)	Direct Flow, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5.1-043	B
34652	Concrete: All (inaccessible areas)	Direct Flow, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5.1-043	B
34653	Concrete: All (inaccessible areas)	Direct Flow, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5.1-043	B
34654	Concrete: All (inaccessible areas)	Direct Flow, Gaseous Release Path, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5.1-043	B
39165	Concrete: All (inaccessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-204	3.5.1-043	B
39166	Concrete: All (inaccessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-204	3.5.1-043	B
39167	Concrete: All (inaccessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-204	3.5.1-043	B

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39168	Concrete: All (inaccessible areas) (Stack)	Gaseous Release Path, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-204	3.5.1-043	B
34969	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5.1-065	B
35530	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5.1-067	B
34971	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5.1-042	B
34972	Concrete: Below-grade exterior (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5.1-047	B
39173	Concrete: Foundation (accessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A9.TP-26	3.5.1-066	B
39174	Concrete: Foundation (accessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-23	3.5.1-064	B
39176	Concrete: Foundation (accessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A9.TP-24	3.5.1-063	B
34973	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5.1-065	B
35531	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5.1-067	B
34975	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5.1-042	B
34976	Concrete: Foundation (inaccessible areas)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5.1-047	B

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39169	Concrete: Foundation (inaccessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A9.TP-212	3.5.1-065	B
39171	Concrete: Foundation (inaccessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A9.TP-29	3.5.1-067	B
39170	Concrete: Foundation (inaccessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A9.TP-108	3.5.1-042	B
39172	Concrete: Foundation (inaccessible areas) (Stack)	Flood Barrier, Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A9.TP-67	3.5.1-047	B
34981	Concrete: Interior	Flood Barrier, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
39181	Concrete: Interior	Flood Barrier, HELB/MELB Barrier, Shelter/Protection, Shielding, Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5.1-067	B
34982	Equipment supports and foundations	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34983	Equipment supports and foundations	Structural Support	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
34984	Hatches/Plugs	Shelter/Protection, Shielding	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34985	Hatches/Plugs	Shelter/Protection, Shielding	Reinforced concrete	Air - Indoor, Uncontrolled	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
34986	Masonry walls: Interior	Shelter/Protection, Shielding, Structural Support	Concrete Block	Air - Indoor, Uncontrolled	Cracking	Masonry Walls (B.2.1.32)	III.A3.T-12	3.5.1-070	B

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
34987	Steel Components: structural steel	Structural Support	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34977	Structural Miscellaneous - Siding	Shelter/Protection	Aluminum	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
34978	Structural Miscellaneous - Siding	Shelter/Protection	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
34980	Structural Miscellaneous - Siding (Blowoff Panels)	Pressure Relief, Shelter/Protection	Aluminum	Air - Outdoor	Cracking, Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	D
34979	Structural Miscellaneous - Siding (Blowoff Panels)	Pressure Relief, Shelter/Protection	Carbon Steel	Air - Indoor, Uncontrolled	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
38302	Structural Miscellaneous - Vent	Filter	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B2.TP-6	3.5.1-093	D

Table 3.5.2-6 Turbine, Waste Handling, and Admin. Structures Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

None.

Table 3.5.2-7 Yard Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35678	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
35681	Bolting (Structural)	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
35682	Bolting (Structural)	Structural Support	Galvanized Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5.1-082	B
35683	Bolting (Structural)	Structural Support	Galvanized Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
35684	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5.1-080	B
35685	Concrete Elements: Anchors	Structural Support	Carbon and Low Alloy Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
35694	Concrete Elements: Anchors	Structural Support	Galvanized Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5.1-082	B
35695	Concrete Elements: Anchors	Structural Support	Galvanized Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
36780	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
36781	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.B5.T-37b	3.5.1-100	B
36782	Concrete Elements: Anchors	Structural Support	Stainless Steel Bolting	Air - Outdoor	Loss of Preload	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5.1-088	B
35710	Concrete Elements: Embedments	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
39136	Concrete: (Tanks) Foundation (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
39137	Concrete: (Tanks) Foundation (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A8.TP-23	3.5.1-064	B
39138	Concrete: (Tanks) Foundation (accessible areas)	Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A8.TP-24	3.5.1-063	B
39147	Concrete: (Tanks) Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A8.TP-212	3.5.1-065	B

Table 3.5.2-7 Yard Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
39148	Concrete: (Tanks) Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A8.TP-29	3.5.1-067	B
39149	Concrete: (Tanks) Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A8.TP-108	3.5.1-042	B
39150	Concrete: (Tanks) Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A8.TP-67	3.5.1-047	B
36698	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
39177	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5.1-067	B
36701	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5.1-064	B
36697	Concrete: Above-grade exterior (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5.1-063	B
39135	Concrete: All	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking and Distortion	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5.1-044	B
35722	Concrete: All (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5.1-054	B
35736	Concrete: All (accessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5.1-054	B
35752	Concrete: All (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5.1-043	B
35753	Concrete: All (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5.1-043	B
35754	Concrete: All (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5.1-043	B
35757	Concrete: Below-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5.1-065	B

Table 3.5.2-7 Yard Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35759	Concrete: Below-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5.1-067	B
35789	Concrete: Below-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5.1-042	B
35766	Concrete: Below-grade exterior (inaccessible areas)	Shelter/Protection, Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5.1-047	B
35768	Concrete: Foundation (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
35772	Concrete: Foundation (accessible areas)	Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5.1-064	B
35776	Concrete: Foundation (accessible areas)	Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5.1-063	B
35785	Concrete: Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5.1-065	B
35787	Concrete: Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5.1-067	B
35788	Concrete: Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5.1-042	B
35791	Concrete: Foundation (inaccessible areas)	Structural Support	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5.1-047	B
36702	Concrete: Interior	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5.1-066	B
39178	Concrete: Interior	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5.1-067	B

Table 3.5.2-7 Yard Structures Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36703	Concrete: Interior	Shelter/Protection, Structural Support	Reinforced concrete	Air - Outdoor	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5.1-064	B
35800	Duct Banks	Shelter/Protection	Reinforced concrete	Groundwater/Soil	Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5.1-065	B
35803	Duct Banks	Shelter/Protection	Reinforced concrete	Groundwater/Soil	Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5.1-067	B
35804	Duct Banks	Shelter/Protection	Reinforced concrete	Groundwater/Soil	Loss of Material (Spalling, Scaling) and Cracking	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5.1-042	B
35807	Duct Banks	Shelter/Protection	Reinforced concrete	Water - Flowing	Increase in Porosity and Permeability, Loss of Strength	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5.1-047	B
35817	Steel Components: structural steel	Structural Support	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
35818	Steel Components: structural steel	Structural Support	Galvanized Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B
35820	Structural Miscellaneous (Unit 1 Rock Dike and Applicable Portion of the Unit 2 Revetment-Ditch System)	Shelter/Protection	Soil, rip-rap, gravel, rock	Air - Outdoor	Loss of Material; Loss of Form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5.1-058	B
35821	Structural Miscellaneous (Unit 1 Rock Dike and Applicable Portion of the Unit 2 Revetment-Ditch System)	Shelter/Protection	Soil, rip-rap, gravel, rock	Water - Flowing	Loss of Material; Loss of Form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5.1-058	B
35833	Structural Miscellaneous (Valve Pit Cover)	Shelter/Protection	Carbon Steel	Air - Outdoor	Loss of Material	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5.1-077	B

Table 3.5.2-7 Yard Structures Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

None.

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 those components and commodities identified in Section 2.5, Scoping and Screening Results: Electrical, 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.

- Cable Connections (Metallic Parts) (2.5.2.5.1)
- Electrical Penetrations (2.5.2.5.2)
- High Voltage Electrical Insulators (2.5.2.5.3)
- Electrical Insulation for Electrical Cables and Connections (2.5.2.5.4)
 - Electrical Insulation for Electrical Cables and Connections
 - Electrical Penetration Pigtails
 - Splices
 - Insulating Portions of Terminal Blocks
 - Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
 - Electrical Conductor Insulation for Inaccessible Instrumentation and Control Cables
 - Electrical Conductor Insulation for Inaccessible Low-Voltage Power Cables
 - Electrical Conductor Insulation for Inaccessible Medium-Voltage Power Cables
- Metal Enclosed Bus (2.5.2.5.5)
- Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors (2.5.2.5.6)

The electrical commodity groups which are addressed in this section are described in the indicated sections. Electrical Penetrations are not subject to their own aging management review in this section in that they are addressed 1) as a TLAA in the Environmental Qualification (EQ) of Electric Components (B.3.1.3) program and 2) in the Primary Containment aging management review.

3.6.2 RESULTS

The following table summarizes the results of the aging management review for electrical components and commodities.

Table 3.6.2-1 Electrical Commodities - Summary of Aging Management Evaluation

3.6.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.6.2.1.1 Cable Connections (Metallic Parts)

Materials

The materials of construction for the Cable Connections (Metallic Parts) are:

- Various Metals Used for Electrical Contacts

Environments

The Cable Connections (Metallic Parts) are exposed to the following environments:

- Air – Indoor, Controlled
- Air – Indoor, Uncontrolled
- Air - Outdoor

Aging Effect Requiring Management

The following aging effects associated with the Cable Connections (Metallic Parts) require management:

- Increased Electrical Resistance of Connection

Aging Management Programs

The following aging management programs manage the aging effects for the Cable Connections (Metallic Parts):

- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.42)

3.6.2.1.2 High Voltage Electrical Insulators

Materials

The materials of construction for the High Voltage Insulators are:

- Porcelain; Malleable Iron; Aluminum; Galvanized Steel; Cement

Environments

The High Voltage Insulators are exposed to the following environments:

- Air – Outdoor

Aging Effect Requiring Management

The High Voltage Insulators have no aging effects requiring management. See subsection 3.6.2.3.1.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the High Voltage Insulators.

3.6.2.1.3 Electrical Insulation for Electrical Cables and Connections

The electrical insulation for electrical cables and connections commodity group was broken down for aging management review of insulation into subcategories based on categorization in NUREG-2191:

- Electrical Conductor Insulation for Electrical Cables and Connections
- Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
- Electrical Conductor Insulation for Inaccessible Instrumentation and Control Cables
- Electrical Conductor Insulation for Inaccessible Low-Voltage Power Cables
- Electrical Conductor Insulation for Inaccessible Medium-Voltage Power Cables

This insulation material commodity group includes insulated cables and connections, electrical penetration pigtails, splices, and insulating portions of terminal blocks.

Materials

The materials of construction for the Electrical Insulation for Electrical Cables and Connections are:

- Various Organic Polymers

Environments

The Electrical Insulation for Electrical Cables and Connections are exposed to the following environments:

- Adverse Localized Environment
- Adverse Localized Environment caused by Significant Moisture

Aging Effect Requiring Management

The following aging effects associated with the Electrical Insulation for Electrical Cables and Connections require management:

- Reduced Electrical Insulation Resistance
- Reduced Electrical Insulation Resistance or Degraded Dielectric Strength

Aging Management Programs

The following aging management programs manage the aging effects for the

Electrical Insulation for Electrical Cables and Connections:

- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.36)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.37)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)

3.6.2.1.4 Metal Enclosed Bus

Materials

The materials of construction for the Metal Enclosed Bus; Bus/Connections; Electrical Insulation, Electrical Insulators; and External Surface of Enclosure Assemblies are:

- Various Metals Used for Electrical Bus and Connections
- Porcelain, xenoy, thermoplastic organic polymers
- Elastomer
- Galvanized Steel; Aluminum
- Carbon Steel

Environments

The Metal Enclosed Bus are exposed to the following environments:

- Air – Indoor, Controlled
- Air – Indoor, Uncontrolled
- Air – Outdoor

Aging Effect Requiring Management

The following aging effects associated with the Metal Enclosed Bus require management:

- Increased Electrical Resistance of Connection
- Reduced Electrical Insulation Resistance
- Surface Cracking, Crazing, Scuffing, Dimensional Change (e.g., “ballooning” and “necking”), Shrinkage, Discoloration, Hardening, and Loss of Strength

- Loss of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Metal Enclosed Bus:

- Metal Enclosed Bus (B.2.1.41)

3.6.2.1.5 Switchyard Bus and Connections

Materials

The materials of construction for the Switchyard Bus and Connections are:

- Various metallic materials

Environments

The Switchyard Bus and Connections are exposed to the following environments:

- Air – Outdoor

Aging Effect Requiring Management

The Switchyard Bus and Connections have no aging effects requiring management. See Subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Switchyard Bus and Connections.

3.6.2.1.6 Transmission Conductors

Materials

The materials of construction for the Transmission Conductors are:

- Aluminum, Steel

Environments

The Transmission Conductors are exposed to the following environments:

- Air – Outdoor

Aging Effect Requiring Management

The Transmission Conductors have no aging effects requiring management. See subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Transmission Conductors.

3.6.2.1.7 Transmission Connections

Materials

The materials of construction for the Transmission Connectors are:

- Aluminum, Steel

Environments

The Transmission Connectors are exposed to the following environments:

- Air – Outdoor

Aging Effect Requiring Management

The Transmission Connectors have no aging effects requiring management. See subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Transmission Connectors.

3.6.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Electrical Components, those programs are addressed in the following subsections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Environmental qualification is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAA's are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed separately in Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," of this SRP-SLR.

Table 3.6.1 Item Number 3.6.1-001: The evaluation of this TLAA is addressed in Section 4.4, "Environmental Qualification (EQ) of Electric Components," of this application.

3.6.2.2.2 Reduced Insulation Resistance Due to Age Degradation of Cable Bus Arrangements Caused by Intrusion of Moisture, Dust, Industrial Pollution, Rain, Ice, Photolysis, Ohmic Heating and Loss of Strength of Support Structures and Louvers of Cable Bus Arrangements Due to General Corrosion and Exposure to Air Outdoor

Reduced insulation resistance due to age degradation of cable bus caused by intrusion of moisture, dust, industrial pollution, rain, ice, photolysis (for ultraviolet sensitive material only), ohmic heating and loss of strength of support structures, covers or louvers of cable bus arrangements due to general corrosion or exposure to air outdoor could occur in cable bus assemblies. Cable bus is a variation of metal enclosed bus (MEB) which is similar in construction to an MEB, but instead of segregated or nonsegregated electrical buses, cable bus is comprised of a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both the cable bus and enclosures are not sealed against intrusion of dust, industrial pollution, moisture, rain, and ice and therefore may introduce debris into the internal cable bus assembly.

Consequently, cable bus construction and arrangements are such that it may not readily fall under a specific GALL-SLR Report AMP (e.g., GALL-SLR Report AMP XI.E1 and AMP XI.E4). GALL-SLR Report AMP XI.E1 calls for a visual inspection of accessible insulated cables and connections subject to an adverse localized environment which may not be applicable to cable bus due to inaccessibility or applicability of the aging mechanisms and effects. GALL-SLR Report AMP XI.E4 includes tests and inspections of the internal and external portions of the MEB. The MEB internal and external inspections and tests may not be applicable to cable bus aging mechanisms and effects. Therefore, the GALL-SLR Report recommends cable bus aging mechanisms and effects be evaluated as a plant-specific further evaluation. The evaluation includes associated AMPs: AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," and AMP XI.S6, "Structures Monitoring." Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.6.1 Item Numbers 3.6.1-029, 3.6.1-030; and 3.6.1-031: There are no Cable Bus: electrical insulation; insulators or Cable Bus: external surface of enclosure assemblies in Electrical Commodities because there is no cable bus in the scope of license renewal, at NMP1.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload for Transmission Conductors, Switchyard Bus, and Connections

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL-SLR Report recommends further evaluation of a plant-specific AMP to demonstrate that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.6.1:

- Item Number 3.6.1-004 - ACSR Transmission Conductors
- Item Number 3.6.1-005 - Transmission Connectors
- Item Number 3.6.1-006 – Switchyard Bus and Connections
- Item Number 3.6.1-007 - Aluminum Transmission Conductors (AAC, ACAR, ACSR)

The transmission conductors, transmission connectors, switchyard bus and connections evaluated for NMP1 are those that are part of the circuits supplying power from the electric utility transmission system to plant buses. The in-scope switchyard bus is found in the 115 kV and the 345 kV power pathways. The 115 kV bus is required for SBO recovery. The 345 kV bus is required to back feed the station service transformer during post fire safe shutdown, when offsite power is credited.

The in scope commodities in the circuits for offsite power sources include 115kV Line #1, 115kV Line #4, 115kV switchyard bus and connections, 345kV Line #8, 345 kV Line #9, 345kV switchyard bus and connections, and 115kV ACSR and 345kV ACSR conductors. The transmission conductor connections are steel and aluminum.

Wind-Induced Abrasion and Fatigue – Transmission Conductors

Table 3.6.1 - Item Number 3.6.1-007: Aluminum/Steel Transmission Conductors: Transmission conductor vibration or sway could be caused by wind loading. Industry experience has shown that the 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 line to vibrate or sway is considered in design and installation. Therefore, the loss of material aging effect that could result from wind-induced transmission conductor vibration or sway is not applicable and would not cause a loss of intended function for transmission conductors for the subsequent period of extended operation.

In addition to causing transmission conductors to vibrate or sway, wind loading can also deliver material that could abrade the conductors. The wind-induced abrasion could lead to loss of material of the transmission conductors. The physical location of NMP1, the typical weather and wind observed at the site, and the material (soil is not sand that is typically associated with abrasion) around the site indicate that the conditions for abrasion that could damage the aluminum transmission conductors is not likely. This is supported by a review of the site's operating experience. Therefore, the loss of material aging effect that could result from wind-induced abrasion to the transmission conductors is not applicable and would not cause a loss of intended function for transmission conductors for the subsequent period of extended operation.

Corrosion – Transmission Conductors

Table 3.6.1 - Item Number 3.6.1-004 - ACSR Transmission Conductors: There are two in scope transmission conductors at NMP1.

The 345 kV Tie-Line conductors are 2167 MCM 72/7 aluminum conductor steel reinforced (ACSR) with one conductor per phase. The 115 kV Tie-Lines conductors are 336.4 MCM 18/1 ACSR with two conductors per phase.

The 2167 MCM 72/7 ACSR transmission conductors are large, substantial transmission conductors. They are approximately 1.74 inches in diameter and are configured with 7 steel conductors wrapped by 72 aluminum conductors. The ultimate strength per American Society for Testing and Materials (ASTM) standards for 2167 MCM/Kcmil 72/7 ACSR is 49,800 lbs, and the heavy load tension design limit for this 2167 MCM/Kcmil circuit at NMP1 is 8,000 lbs.

The 336.4 MCM 18/1 ACSR transmission conductors are large, substantial transmission conductors. They are approximately 0.68 inches in diameter and are configured with 1 steel conductor wrapped by 18 aluminum conductors. The ultimate strength per American Society for Testing and Materials (ASTM) standards for 336.4 MCM 18/1 ACSR is 8,960 lbs, and the heavy load tension design limit for this 336.4 MCM 18/1 ACSR circuit at NMP1 is 3,000 lbs.

The Constellation Transmission and Distribution design practices follow the NESC methodologies. The NESC requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also states that the maximum tension of a conductor must be designed to withstand heavy load requirements, which include consideration of ice, wind, and temperature.

The most prevalent contribution to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality which includes suspended particles chemistry, sulfur dioxide (SO₂) concentration in air, precipitation, fog chemistry, and meteorological conditions.

Ontario Hydroelectric performed a study that is documented in 1992 IEEE Transactions on Power Delivery. The papers present the methodology and results of both field and laboratory tests on ACSR conductors from Ontario Hydroelectric's older transmission lines. The field tests were performed on-line, to detect steel core galvanizing loss by using an overhead line conductor corrosion detector. Potential conductor degradation is measured by an eddy current sensor that travels along the conductor, between transmission towers. Laboratory tests were performed for fatigue, tensile strength, torsional ductility, and electrical performance. The fatigue tests simulating 50 years of service life were performed to assess existing cables as well as a new cable. The tensile strength was assessed by the individual wire method, and torsional ductility was assessed by the twist to failure method. Both the tensile strength and torsional ductility tests were performed in accordance with published standards. Additional considerations in the performance of these aging assessments included metallurgical data and analysis for potential environmental contributors. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-

year-old ACSR conductor due to corrosion. The NMP1 in scope transmission conductors are the same type of transmission conductors evaluated in the Ontario Hydroelectric study and in the EPRI License Renewal Electrical Handbook. The test methodology as published in the IEEE Transactions on Power Delivery is applicable to in scope NMP1 ACSR transmission conductors.

NMP1 is located in an area where industrial airborne particle concentrations are comparatively low, since it is located in a rural area with no heavy industry nearby. In the Ontario Hydroelectric Study, the conductors most affected by atmospheric corrosion were located in areas subject to pollution sources and a major urban area. Therefore, the environmental impact to the NMP1 transmission conductors (which are located in a rural area) are bounded by the Ontario Hydroelectric conductors (which were located in polluted and urban environments).

An example presented in the EPRI License Renewal Handbook, 3002010402, compares a 4/0 conductor to the results of the Ontario Hydroelectric Study. The EPRI License Renewal Electrical Handbook evaluation documents that a 4/0 ACSR conductor (equivalent to a 211 MCM conductor size), which was included in the Ontario Hydroelectric study, has the smallest ultimate strength margin. Larger, more substantial transmission conductors (e.g., 336.4 MCM 30/7 conductors) that had a greater strength margin were bounded by the 4/0, 6/1 ACSR conductor example. The NMP1 transmission conductors are physically more substantial than the limiting 4/0 ACSR conductor. NESC requirements and the handbook guidance are used to evaluate the in scope ACSR transmission conductors at NMP1.

Assuming a 30 percent loss of strength as demonstrated by the Ontario Hydroelectric tests, there would still be a significant margin between the NESC Design Strength and postulated ultimate strength at 80 years.

- The initial margin between the NMP1 design limit and the ultimate strength for the 2167 MCM and 336.4 MCM ACSR transmission conductors is 41,800 and 5,960 lbs. respectively, allowing 84 and 66 percent margin, respectively.
- The Ontario Hydroelectric study showed a 30 percent loss of composite conductor strength in an 80 year old conductor. In the case of the 2167 MCM and 336.4 MCM ACSR transmission conductors, a 30 percent loss of ultimate strength would result in a postulated ultimate strength at 80 years of 34,860 and 6,272 lbs. respectively, allowing 54 and 36 percent margin respectively between the postulated ultimate strength at 80 years and the NMP1 design limit.
- Comparing the postulated ultimate strength at 80 years (34,860 and 6,272 lbs.) to both the NMP1 design limit (8,000 and 3,000 lbs.) and to the NESC design strength (29,880 and 5,376 lbs.) demonstrates margin for the NMP1 ACSR transmission conductors as they age. The design and physical construction of the NMP1 in scope transmission conductors during the subsequent period of extended operation is bounded by the handbook analysis of the 4/0 ACSR conductor and is also bounded by the Ontario Hydroelectric study.

	2167 MCM 72/7 ACSR Transmission Conductor	336.4 MCM 18/1 ACSR Transmission Conductor
Ultimate Strength, New	49,800 lbs.	8,960 lbs.
Postulated Ultimate Strength at 80 Years	34,860 lbs.	6,272 lbs.
NESC Design Strength, Required, New	29,880 lbs.	5,376 lbs.
NESC Heavy Load Tension, NMP1 Design Limit	8,000 lbs.	3,000 lbs.

In conclusion, the in scope NMP1 transmission conductors are bounded by the Ontario Hydroelectric study by test methodology, design and construction, and environment. The above evaluations demonstrate with reasonable assurance that transmission conductors will have ample strength margin through the subsequent period of extended operation. Therefore, based on NMP1 design and confirmed by operating experience, the loss of transmission conductor strength does not require aging management activities for the subsequent period of extended operation.

Oxidation or Loss of Preload – Transmission Connectors

Table 3.6.1 - Item Number 3.6.1-005 - Transmission Connectors: Transmission connectors employ good utility practice for bolting. The connections are of non-corrosive material and are torqued at the time of installation to avoid loss of preload. The transmission connectors are designed and installed using stainless steel bolting material including lock washers that provide vibration absorption and prevent loss of preload. Based on NMP1 design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for NMP1 transmission connectors.

Wind-Induced Abrasion and Fatigue – Switchyard Bus

Table 3.6.1 - Item Number 3.6.1-006 – Switchyard Bus and Connections: NMP1 is located on the shore of Lake Ontario, near Oswego, New York. Switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components, such as concrete footings and structural steel. The switchyard bus is rigidly mounted and is, therefore, not subject to abrasion induced by wind loading. Therefore, based on NMP1 design and confirmed by operating experience, wind-induced abrasion and fatigue are not applicable aging mechanisms for the NMP1 switchyard bus.

Oxidation or Loss of Preload – Switchyard Bus Connections

Table 3.6.1 - Item Number 3.6.1-006 – Switchyard Bus and Connections: Switchyard bus connections employ good utility practice for bolting. The connections are of non-corrosive material and are torqued at the time of installation to avoid loss of preload. The switchyard bus bolted connections are designed and installed using stainless steel bolting material including lock washers that provide

vibration absorption and prevent loss of preload. Therefore, based on NMP1 design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for NMP1 switchyard bus connections.

Conclusion

Aging management activities for NMP1 switchyard bus and connections, transmission conductors, and transmission connectors are not required for the subsequent period of extended operation.

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 Section B.1.3.

3.6.2.2.5 Ongoing Review of Operating Experience

An ongoing review of operating experience is addressed in Appendix A, Section A.1.6 and Appendix B, Section B.1.4.

3.6.2.3 AMR Results Not Consistent With or Not Addressed in the GALL Report

3.6.2.3.1 High Voltage Electrical Insulators

Table 3.6.1 Item Numbers 3.6.1-002 and 3.6.1-003 – High Voltage Electrical Insulators: Potential aging effects for in scope high voltage insulators were evaluated to determine if the GALL-SLR AMP XI.E7, “High Voltage Insulators” was to be implemented for NMP1 subsequent license renewal. The high voltage insulators evaluated for NMP1 provide physical support for switchyard bus, transmission conductors, and switchyard active components that are part of the circuits that supply power from the electric utility transmission system to plant buses. These circuits provide power to in scope license renewal components used for coping during and recovery from a station blackout event and during post fire safe shutdown, when offsite power is credited.

Airborne Contamination

Various airborne materials such as dust, salt, fog, cooling tower plume, and industrial effluents can contaminate insulator surfaces (i.e., foreign debris). The buildup of surface contamination is gradual and in most areas such contamination is washed away by rain; the glazed insulator surface aids this contamination removal. A large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover.

Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near the seacoast where salt spray is prevalent, near facilities that discharge soot or other airborne pollutants, or at sites where the cooling tower plume discharges such that it may deposit contaminants on switchyard components and transmission lines.

NMP1 is not located near a seacoast. It is located on Lake Ontario in Oswego County, New York. NMP1 is located in an area where industrial airborne particle

concentrations are comparatively low, since it is located in a rural area with minimal heavy industry nearby. Additionally, NMP1 does not have cooling towers. The Nine Mile Point Nuclear Station, Unit 2 (NMP2) cooling tower is located east of NMP1 in scope switchyard and transmission components and commodities. The elevated release of the NMP2 cooling tower poses no significant contamination risk. Minor contamination is washed away by rainfall or snow. Cumulative build up high voltage insulation contamination has not been experienced and is not expected to occur at NMP1 for in scope high voltage insulators. Plant-specific OE from 2016 to 2026 was reviewed for degradation of glazing on the porcelain for high voltage insulators. This review found that this aging mechanism was not experienced at NMP1.

Porcelain cracking or breaking is most commonly caused by an object striking the high voltage insulator. Porcelain cracking has also occurred when cement that binds the parts together expands excessively. This phenomenon is known as cement growth; it occurs as a result of improper manufacturing that makes the cement more susceptible to moisture penetration. Porcelain cracking or breaking has not been experienced and is not expected to occur at NMP1 for in scope high voltage insulators. Plant-specific OE from 2016 to 2026 was reviewed for porcelain cracking on high voltage insulators. This review found that this aging mechanism not experienced at NMP1.

Based on NMP1's location and confirmed by its operating experience, porcelain cracking and surface contamination per NUREG-2191 are not significant aging effects for NMP1. Therefore, aging management of porcelain cracking and surface contamination from dust, salt, fog, cooling tower plume, glazing degradation, and industrial effluents are not applicable to NMP1 for the subsequent period of extended operation.

Loss of Material - Mechanical Wear or Corrosion

Loss of material of high voltage insulators can occur due to movement of transmission conductors due to significant wind. Significant wind can result in mechanical wear of metallic parts. Surface corrosion of metallic parts can occur if galvanized or other protective coatings are worn from significant wind induced movement of transmission conductors.

Mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Movement can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swinging is frequent enough, it could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, experience has shown that the transmission conductors do not normally swing and that when they do swing due to substantial wind, they do not continue to swing for very long once the wind has subsided. Wind loading that can cause a transmission line insulator to sway is considered and minimized during design and installation.

Loss of material of high voltage insulators can also occur due to airborne contamination. A large buildup of contamination could result in corrosion of the metallic parts of the high voltage insulator which if significant could impact its

structural integrity. Although rare, surface rust of the metallic cap may form where galvanizing is burnt off due to flashover from lightning strikes.

High voltage insulator loss of material due to mechanical wear or corrosion caused by movement of conductors due to significant wind per NUREG-2191 are not significant aging concerns at NMP1. These conditions have not been identified during routine switchyard inspections. Review of operating experience did not identify these aging mechanisms. Therefore, aging management of loss of material due to mechanical wear or corrosion is not applicable to NMP1 for the subsequent period of extended operation.

Conclusion

Aging management activities for NMP1 high voltage insulators are not required for the subsequent period of extended operation; therefore, the GALL-SLR AMP XI.E7, “High Voltage Insulators” is not applicable to NMP1.

3.6.2.4 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with Electrical Commodities:

Section 4.4, Environmental Qualification (EQ) of Electric Components.

3.6.3 CONCLUSION

The Electrical Components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Electrical Components are identified in the summaries in Section 3.6.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Electrical Components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-001	Electrical equipment subject to Title 10 of the Code of Federal Relations (CFR) 50.49 Environmental Qualification (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, 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	The 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	Environmental Qualification is a TLAA; further evaluation is documented in subsection 3.6.2.2.1.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-002	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement, toughened glass; polymers; silicone rubber; fiber glass, aluminum alloy exposed to air – outdoor	Loss of material on metallic connectors due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	AMP XI.E7, "High-Voltage Insulators"	No	Not Applicable. Based on NMP1 design and operating experience, loss of material is not an applicable aging effect for high voltage insulators in Electrical Commodities. In scope high voltage insulators composed of porcelain, malleable iron, aluminum, galvanized steel, and cement in an air - outdoor environment are not subject to loss of material on metallic connectors due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind. NMP1 does not have high voltage insulators composed of toughened glass, polymers, silicone rubber, fiber glass or aluminum alloy. See subsection 3.6.2.3.1

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-003	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement, toughened glass; polymers; silicone rubber; fiber glass, aluminum alloy exposed to air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination; peeling of silicone rubber sleeves for polymer insulators; or degradation of glazing on porcelain insulators	AMP XI.E7, "High-Voltage Insulators"	No	Not Applicable. Based on NMP1 geographic location, design, and operating experience, reduced insulation resistance is not an applicable aging effect for high voltage insulators in Electrical Commodities. In scope high voltage insulators composed of porcelain, malleable iron, aluminum, galvanized steel, and cement in an air - outdoor environment are not subject to reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume, industrial effluent contamination or degradation of glazing on porcelain insulators. NMP1 does not have high voltage insulators composed of toughened glass, polymers, silicone rubber, fiber glass or aluminum alloy. NMP1 does not have high voltage insulators composed of silicone rubber and therefore will not experience peeling of silicone rubber sleeves. See subsection 3.6.2.3.1.
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 aluminum conductor steel reinforced (ACSR)	Yes	Not Applicable. See subsection 3.6.2.2.3.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
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	Not Applicable. See subsection 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	Not Applicable. See subsection 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), aluminum conductor aluminum alloy reinforced (ACAR), and ACSR	Yes	Not Applicable. See subsection 3.6.2.2.3.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-008	Electrical insulation for electrical cables and connections (including terminal blocks, etc.) composed of various organic polymers (e.g., ethylene propylene rubber [EPR], silicone rubber [SR], ethylene propylene diene monomer [EPDM], cross-linked polyethylene [XLPE]) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced electrical insulation resistance due to thermal/thermooxidative degradation of organics, radiolysis, and photolysis (ultraviolet [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. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.36) program will be used to manage reduced electrical insulation resistance of the various organic polymers in electrical insulation for electrical cables and connections exposed to adverse localized environments.
3.6.1-009	Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor 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/thermooxidative 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. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.37) program will be used to manage reduced electrical insulation resistance of the various organic polymers in electrical insulation for electrical cables and connections used in instrumentation circuits exposed to adverse localized environments.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-010	Electrical conductor insulation for inaccessible power, instrumentation, and control cables (e.g., installed in duct bank, buried conduit or direct buried) composed of various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield exposed to an adverse localized environment caused by significant moisture	Reduced electrical IR 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. The Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38), Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39), and Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40) programs will be used to manage reduced electrical insulation resistance or degraded dielectric strength of the various organic polymers in electrical conductor insulation for inaccessible medium voltage (2 kV to 35 kV) power, instrumentation and control, and low voltage (typically < 1 kV but no greater than 2 kV) cables exposed to adverse localized environments caused by significant moisture.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-011	Metal enclosed bus (MEB): 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. The Metal Enclosed Bus (B.2.1.41) program will be used to manage surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, and hardening or loss of strength of metal enclosed bus: enclosure assemblies composed of elastomers exposed to air – indoor controlled, air – indoor uncontrolled, or air – outdoor.
3.6.1-012	MEB: 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. The Metal Enclosed Bus (B.2.1.41) program will be used to manage increased electrical resistance of connection of the various metals used for electrical bus and connections in metal enclosed bus exposed to air - indoor controlled, air - indoor uncontrolled, or air - outdoor.
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 IR due to thermal/thermo-oxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	AMP XI.E4, "Metal Enclosed Bus"	No	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.1.41) program will be used to manage reduced electrical insulation resistance of the porcelain and various organic polymers in metal enclosed bus: electrical insulation, electrical insulators exposed to air - indoor controlled, air – indoor uncontrolled, or air - outdoor.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-014	MEB: 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. The Metal Enclosed Bus (B.2.1.41) program will be used to manage loss of material of the external surfaces of the steel metal enclosed bus enclosure assemblies exposed to air - indoor uncontrolled, or air - outdoor.
3.6.1-015	MEB: 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	Consistent with NUREG-2191. The Metal Enclosed Bus (B.2.1.41) program will be used to manage loss of material of the external surfaces of the galvanized steel or aluminum metal enclosed bus enclosure assemblies exposed to air - outdoor.
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. There are no fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor uncontrolled in Electrical Commodities. See Section 2.5.2.3.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	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. There are no fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air-indoor controlled or uncontrolled in Electrical Commodities. See Section 2.5.2.3.
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. There are no Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor controlled or uncontrolled in Electrical Commodities. See Section 2.5.2.3.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
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. The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.42) program will be used to manage increased electrical resistance of connection of the various metals used for electrical contacts cable connections (metallic parts) exposed to air-indoor controlled, air - indoor uncontrolled, or air – outdoor in Electrical Commodities.
3.6.1-020	PWR Only				
3.6.1-021	Transmission conductors composed of aluminum exposed to air – outdoor	Loss of conductor strength due to corrosion	None - for ACAR and AAC	No	Not Applicable. There are no aging effects to be managed for all aluminum transmission conductors exposed to air - outdoor environments in Electrical Commodities.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-022	Fuse holders (not part of active equipment): insulation material composed of electrical insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate, and other, exposed to air – indoor controlled or uncontrolled	Reduced electrical IR due to thermal/thermooxidative 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. There are no 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 in Electrical Commodities. See Section 2.5.2.3.
3.6.1-023	MEB: external surface of enclosure assemblies. Galvanized steel; aluminum. air – indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191. There are no aging effects to be managed for external surface of enclosure assemblies.
3.6.1-024	MEB: external surface of enclosure assemblies. Steel air – indoor controlled	None	None	No	Consistent with NUREG-2191. There are no aging effects to be managed for external surface of enclosure assemblies
3.6.1-025	This Item Number is not listed in NUREG-2192.				
3.6.1-026	This Item Number is not listed in NUREG-2192.				

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
3.6.1-027	Cable bus: external surface of enclosure assemblies. Galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Not Applicable. There are no galvanized steel or aluminum cable bus, external surfaces of enclosure assemblies, exposed to air - indoor controlled or uncontrolled in Electrical Commodities. See section 3.6.2.2.2.
3.6.1-028	This Item Number is not listed in NUREG-2192.				
3.6.1-029	Cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical IR 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	Not Applicable. There are no cable bus, electrical insulation and insulators, exposed to air - indoor, controlled, air - indoor uncontrolled, or air - outdoor in Electrical Commodities. See section 3.6.2.2.2.
3.6.1-030	Cable bus: external surface of enclosure assemblies composed of steel, exposed to air - indoor uncontrolled or air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes	Not Applicable. There are no cable bus, external surface of enclosure assemblies, composed of steel, exposed to air - indoor uncontrolled or air - outdoor in Electrical Commodities See section 3.6.2.2.2.

Table 3.6.1 Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs (AMP)/ Time-Limited Aging Analysis (TLAA)	Further Evaluation Recommended	Discussion
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	Not Applicable. There are no cable bus, external surface of enclosure assemblies, composed of galvanized steel or aluminum; exposed to air - outdoor in Electrical Commodities. See section 3.6.2.2.2.
3.6.1-032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not Applicable. There are no cable bus, external surface of enclosure assemblies, composed of steel exposed to air - indoor controlled in Electrical Commodities. See section 3.6.2.2.2.

Table 3.6.2-1 Electrical Commodities Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
35077	Cable connections (metallic parts)	Electrical Continuity	Various metals used for electrical contacts	Air – Indoor, Controlled, or Uncontrolled, Air – Outdoor	Increased Electrical Resistance of Connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.42)	VI.A.LP-30	3.6.1-019	A
37323	Electric equipment subject to 10 CFR 50.49 EQ requirements	Electrical Continuity	Various metallic materials	10 CFR 50.49 EQ environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
38134	Electric equipment subject to 10 CFR 50.49 EQ requirements	Electrical Continuity	Various metallic materials	Adverse localized environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
37309	Electric equipment subject to 10 CFR 50.49 EQ requirements	Insulate (Electrical)	Various polymeric materials	10 CFR 50.49 EQ environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
38136	Electric equipment subject to 10 CFR 50.49 EQ requirements	Insulate (Electrical)	Various polymeric materials	Adverse localized environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6.1-001	A
36644	Electrical conductor insulation for electrical cables and connections	Insulate (Electrical)	Various organic polymers	Adverse localized environment	Reduced Electrical Insulation Resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.36)	VI.A.LP-33	3.6.1-008	A
35760	Electrical conductor insulation for inaccessible instrumentation and control cables	Insulate (Electrical)	Various organic polymers	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 (B.2.1.39)	VI.A.LP-35b	3.6.1-010	A
35083	Electrical conductor insulation for inaccessible low-voltage cables - typical operating voltage of < 1 kV but no greater than 2 kV	Insulate (Electrical)	Various organic polymers	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 (B.2.1.40)	VI.A.LP-35c	3.6.1-010	A

Table 3.6.2-1 Electrical Commodities Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36951	Electrical conductor insulation for inaccessible medium-voltage cables - typical operating range of 2 kV to 35 kV	Insulate (Electrical)	Various organic polymers	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 (B.2.1.38)	VI.A.LP-35a	3.6.1-010	A
35805	Electrical insulation for electrical cables and connections used in instrumentation circuits	Insulate (Electrical)	Various organic polymers	Adverse localized environment	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 (B.2.1.37)	VI.A.LP-34	3.6.1-009	A
39001	High-voltage electrical insulators	Insulate (Electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement	Air – Outdoor	None	none	VI.A.LP-32	3.6.1-002	I, 4
39001	High-voltage electrical insulators	Insulate (Electrical)	Porcelain; malleable iron; aluminum; galvanized steel; cement	Air – Outdoor	None	None	VI.A.LP-28	3.6.1-003	I, 4
35911	Metal enclosed bus: bus/connections	Electrical Continuity	Various metals	Air – Indoor, Controlled, or Uncontrolled, Air – Outdoor	Increased Electrical Resistance of Connection	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-25	3.6.1-012	A
35904	Metal enclosed bus: electrical insulation, electrical insulators	Insulate (Electrical)	Porcelain; xenoy; thermoplastic organic polymers	Air – Indoor, Controlled, or Uncontrolled, Air – Outdoor	Reduced Electrical Insulation Resistance	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-26	3.6.1-013	A
36609	Metal enclosed bus: enclosure assemblies	Shelter, Protection	Elastomers	Air – Indoor, Controlled, or Uncontrolled, Air – Outdoor	Surface Cracking, Cracking, Scuffing, Dimensional Change (e.g. "Ballooning" and "Necking"), Shrinkage, Discoloration, Hardening and Loss of Strength	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-29	3.6.1-011	A
36623	Metal enclosed bus: external surface of enclosure assemblies	Shelter, Protection	Carbon Steel	Air - Indoor, Controlled	None	None	VI.A.LP-44	3.6.1-024	A

Table 3.6.2-1 Electrical Commodities Summary of Aging Management Evaluation

AMR ID	Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
36624	Metal enclosed bus: external surface of enclosure assemblies	Shelter, Protection	Carbon Steel	Air - Indoor, Uncontrolled, Air – Outdoor	Loss of Material	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-43	3.6.1-014	A
36622	Metal enclosed bus: external surface of enclosure assemblies	Shelter, Protection	Galvanized Steel; Aluminum	Air - Indoor, Controlled, or Uncontrolled	None	None	VI.A.LP-41	3.6.1-023	A
36621	Metal enclosed bus: external surface of enclosure assemblies	Shelter, Protection	Galvanized Steel; Aluminum	Air – Outdoor	Loss of Material	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-42	3.6.1-015	A
37310	Switchyard bus and connections	Electrical Continuity	Various metallic materials	Air - Outdoor	None	None	VI.A.LP-39	3.6.1-006	I, 1
37311	Transmission conductors	Electrical Continuity	Aluminum; steel	Air - Outdoor	None	None	VI.A.LP-47	3.6.1-007	I, 2
37312	Transmission conductors	Electrical Continuity	Aluminum; steel	Air - Outdoor	None	None	VI.A.LP-38	3.6.1-004	I, 2
37313	Transmission connectors	Electrical Continuity	Aluminum; steel	Air - Outdoor	None	None	VI.A.LP-48	3.6.1-005	I, 3

Table 3.6.2-1 Electrical Commodities Summary of Aging Management Evaluation

Notes	Definition of Note
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 NUREG-2191 AMP.
E	Consistent with NUREG-2191 item for material, environment and aging effect, but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
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.

Plant Specific Notes:

1. The evaluation in Section 3.6.2.2.3 determined that no AMP is required for switchyard bus and connections.
2. The evaluation in Section 3.6.2.2.3 determined that no AMP is required for ACSR transmission conductors.
3. The evaluation in Section 3.6.2.2.3 determined that no AMP is required for transmission connectors.
4. The evaluation in Section 3.6.2.3.1 determined that no aging effects requiring management are applicable to the High Voltage Insulators at NMP1. Therefore, no AMP is required for High-Voltage Insulators.

4.0 TIME-LIMITED AGING ANALYSES

4.1 IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES (TLAAS)

Pursuant to 10 CFR 54.3, Time-Limited Aging Analyses (TLAAs) are those licensee calculations and analyses that meet all six criteria below:

1. Involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);
2. Consider the effects of aging;
3. Involve time-limited assumptions defined by the current operating term, for example, 40 years;
4. Were determined to be relevant by the licensee in making a safety determination;
5. Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b); and
6. Are contained or incorporated by reference in the current licensing basis (CLB).

4.1.1 IDENTIFICATION OF NMP1 TIME-LIMITED AGING ANALYSES

TLAAs have been identified for Nine Mile Point Nuclear Station, Unit 1 (NMP1) using methods consistent with those provided in 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” (Reference 4.8.2) and NUREG-2192, Revision 1, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP),” (Reference 4.8.3).

A list of potential generic TLAAs was assembled from NRC and industry guidance including:

- NUREG-2191, Revision 1, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report” (Reference 4.8.4)
- NUREG-2192, Revision 1, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants” (Reference 4.8.3)
- NEI 95-10, Revision 6, “Industry Guideline for Implementing the Requirements of 10 CFR 54, the License Renewal Rule” (Reference 4.8.5)
- NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal” (Reference 4.8.6)
- The 10 CFR 54 Final Rule, Statement of Considerations

- Prior license renewal and subsequent license renewal applications, NRC Requests for Additional Information, and NRC Safety Evaluation Reports for these applications.

In addition, the NMP1 CLB documentation was searched to identify potential TLAAs. The document search included the following:

- Updated Final Safety Analysis Report (UFSAR)
- Technical Specifications and Bases
- NMP's first License Renewal Application (LRA)
- NRC Safety Evaluation Reports (SERs)
- Docketed licensing correspondence, including those associated with the first LRA and associated NRC SERs which approved the application
- Design Bases Documents (DBDs)
- General Electric Design Analyses and Reports
- MP Machinery and Testing (MPM) Reports
- Structural Integrity Associates Design Analyses and Reports
- Teledyne Engineering Services Design Analyses and Reports
- Asset Suite 9 Records
- Environmental Qualification Binders
- Engineering Specifications
- Engineering Change Requests
- Corrective Action Program Reports
- 10 CFR 50.12 Exemption Requests
- Inservice Inspection Relief Requests

Each potential TLAA was reviewed against the six criteria from 10 CFR 54.3(a) listed in SLRA Section 4.1 above. Those that meet all six criteria were identified as TLAAs that require evaluation for the subsequent period of extended operation. While the current license term referred to in 10 CFR 54.3 is now 60 years for NMP1, all TLAAs that were identified in the first LRA have been evaluated to determine if they were TLAAs for subsequent license renewal.

4.1.2 EVALUATION OF NMP1 TIME-LIMITED AGING ANALYSES

Each NMP1 TLAA has been evaluated for the subsequent period of extended

operation. Each evaluation contains the following information:

TLAA Description: A description of the CLB analysis that has been identified as a TLAA, including a description of the aging effect evaluated, the time-limited variable used in the analysis, and its basis.

TLAA Evaluation: An evaluation of the TLAA for the subsequent period of extended operation. This section provides information associated with 80 years of operation for comparison with the information used in the TLAA that considered the previous license term of operation. This evaluation provides the basis for the disposition, which falls into one of the three disposition categories described below.

TLAA Disposition: The disposition is classified in accordance with one of the acceptance criteria from 10 CFR 54.21(c)(1) specified below in SLRA Section 4.1.3.

4.1.3 ACCEPTANCE CRITERIA

10 CFR 54.21, Contents of application – technical information, states 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 §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 must be used to disposition each TLAA identified for the subsequent period of extended operation for NMP1. The methods used are identified in each TLAA evaluation section.

4.1.4 SUMMARY OF RESULTS

SLRA Table 4.1-1 lists the example TLAAs provided in NUREG-2192, Revision 1, Tables 4.1-2 and 4.7-1, and specifies whether they have been identified as TLAAs for the NMP1 SLR application. Those examples with a “Yes” entry apply for NMP1 and the section(s) where the TLAA(s) are evaluated are provided. Those examples with a “No” entry do not apply for NMP1 and no TLAA was identified for these categories, either because they are associated with design features not employed at NMP1 or because no analysis was identified that met all six TLAA criteria.

SLRA Table 4.1-2 is a summary of the TLAAs identified for the NMP1 SLRA. The TLAAs are grouped by affected component and aging effect analyzed. The table entries also state the disposition method used in evaluating the TLAA and include a reference to the applicable SLRA section where the TLAA is evaluated for the subsequent period of extended operation.

4.1.5 IDENTIFICATION OF EXEMPTIONS PURSUANT TO 10 CFR 50.12

Exemptions pursuant to 10 CFR 50.12 currently in effect for NMP1 were reviewed to determine if they are based upon a TLAA. There were no exemptions pursuant to 10 CFR 50.12 identified that are currently in effect that are based upon or are associated with a TLAA.

TABLE 4.1-1 REVIEW OF GENERIC TLAAs LISTED IN NUREG-2192, REVISION 1, TABLES 4.1-2 AND 4.7-1		
NUREG-2192, Revision 1, Examples of Potential Generic and Plant-Specific TLAAs	Applies for NMP1?	SLRA Section
NUREG-2192, Revision 1, Table 4.1-2 – Generic TLAAs		
Neutron Fluence	Yes	4.2.1
Pressurized Thermal Shock (PWRs Only)	No	N/A
Upper Shelf Energy (PWRs and BWRs)	Yes	4.2.2
Pressure Temperature (P-T) Limits (PWRs and BWRs)	Yes	4.2.4
Low Temperature Overpressure Protection System Setpoints (PWRs Only)	No	N/A
Ductility Reduction Evaluation for Reactor Internals (B&W designed PWRs only)	No	N/A
RPV Circumferential Weld Relief–Probability of Failure and Mean Adjusted Reference Temperature Analysis for the RPV Circumferential Welds (BWRs only)	Yes	4.2.5
Reactor Vessel Axial Weld Probability of Failure and Mean Adjusted Reference Temperature Analysis (BWRs only)	Yes	4.2.6
Metal Fatigue of Class 1 Components	No	N/A
Metal Fatigue of Non-Class 1 Components	Yes	4.3
Environmentally-Assisted Fatigue	Yes	4.3.5
High Energy Line Break Analyses	Yes	4.3.4
Cycle-Dependent Fracture Mechanics or Flaw Evaluations	Yes	4.7.1 4.7.2 4.7.3 4.7.6 4.7.7
Cycle-Dependent Fatigue Waivers	No	N/A
Environmental Qualification of Electrical Equipment	Yes	4.4
Concrete Containment Tendon Prestress	No	N/A
Containment Liner Plate, Metal Components, and Penetrations Fatigue	Yes	4.6

TABLE 4.1-1 REVIEW OF GENERIC TLAAs LISTED IN NUREG-2192, REVISION 1, TABLES 4.1-2 AND 4.7-1		
NUREG-2192, Revision 1, Examples of Potential Generic and Plant-Specific TLAAs	Applies for NMP1?	SLRA Section
NUREG-2192, Revision 1, Table 4.7-1 – Examples of Potential Plant-Specific TLAA Topics (BWRs)		
Reflood Thermal Shock of the Reactor Pressure Vessel	No	N/A
Reflood Thermal Shock of the Core Shroud and Other Reactor Vessel Internals	No	N/A
Loss of Preload for Core Plate Rim Hold-Down Bolts	No	N/A
Erosion of the Main Steam Line Flow Restrictors	No	N/A
Susceptibility to Irradiation-Assisted Stress Corrosion Cracking	No	N/A
Fatigue of Cranes (Crane Cycle Limits)	Yes	4.7.8
Fatigue of the Spent Fuel Pool Liner	Yes	4.6.8
Corrosion Allowance Calculations	No	N/A
Flaw Growth due to Stress Corrosion Cracking	Yes	4.7.2 4.7.7
Predicted Lower Limit	No	N/A

**TABLE 4.1-2
SUMMARY OF RESULTS – NMP1 TIME-LIMITED AGING ANALYSES**

TLAA DESCRIPTION	DISPOSITION	SLRA SECTION
IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES (TLAAS)		4.1
Identification of NMP1 Time-Limited Aging Analyses		4.1.1
Evaluation of NMP1 Time-Limited Aging Analyses		4.1.2
Acceptance Criteria		4.1.3
Summary of Results		4.1.4
Identification of Exemptions Pursuant to 10 CFR 50.12		4.1.5
REACTOR VESSEL AND INTERNALS NEUTRON EMBRITTLEMENT ANALYSES		4.2
Neutron Fluence Analyses		4.2.1
Reactor Pressure Vessel Neutron Fluence Analyses	§54.21(c)(1)(ii)	4.2.1.1
Reactor Pressure Vessel Internals Neutron Fluence Analyses	§54.21(c)(1)(ii)	4.2.1.2
Reactor Pressure Vessel Upper-Shelf Energy (USE) Analyses	§54.21(c)(1)(ii)	4.2.2
Reactor Pressure Vessel Adjusted Reference Temperature (ART) Analyses	§54.21(c)(1)(ii)	4.2.3
Reactor Pressure Vessel Pressure-Temperature (P-T) Limits	§54.21(c)(1)(iii)	4.2.4
Reactor Pressure Vessel Circumferential Weld Failure Probability Analysis	§54.21(c)(1)(iii)	4.2.5
Reactor Pressure Vessel Axial Weld Failure Probability Analysis	§54.21(c)(1)(ii)	4.2.6
Core Shroud Stabilizer Assembly Preload Relaxation Analysis	§54.21(c)(1)(i)	4.2.7
METAL FATIGUE ANALYSES		4.3
Transient Cycle and Cumulative Usage Projections for 80 Years		4.3.1
Reactor Vessel and Piping Fatigue Analyses	§54.21(c)(1)(iii)	4.3.2
Fatigue of the Emergency Condensers	§54.21(c)(1)(iii)	4.3.3
ASME Section III, Class 2 & 3, and ANSI B31.1 Allowable Stress Analysis and HELB Exclusions of Recirculation Piping Analysis	§54.21(c)(1)(i)	4.3.4
Environmentally Assisted Fatigue Analysis	§54.21(c)(1)(iii)	4.3.5
Reactor Vessel Internals Fatigue Analyses		4.3.6
Core Shroud Support Stabilizer Tie Rod and Conical Support Fatigue Analysis	§54.21(c)(1)(ii)	4.3.6.1
Core Shroud Vertical Weld Repair Clamps Fatigue Analysis	§54.21(c)(1)(ii)	4.3.6.2

TABLE 4.1-2
SUMMARY OF RESULTS – NMP1 TIME-LIMITED AGING ANALYSES

TLAA DESCRIPTION	DISPOSITION	SLRA SECTION
Core Shroud Stabilizer Modified Upper Supports Fatigue Analyses	§54.21(c)(1)(i)	4.3.6.3
Steam Dryer Support Bracket Fatigue Analysis	§54.21(c)(1)(ii)	4.3.6.4
ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT		4.4
Environmental Qualification of Electric Equipment	§54.21(c)(1)(iii)	4.4.1
CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS		4.5
Concrete Containment Tendon Prestress Analysis	No TLAA	4.5
PRIMARY CONTAINMENT FATIGUE ANALYSES		4.6
Torus Shell Fatigue Analysis	§54.21(c)(1)(iii)	4.6.1
Vent System Fatigue Analysis	§54.21(c)(1)(i)	4.6.2
Torus Attached Piping Analysis	§54.21(c)(1)(iii)	4.6.3
Fatigue of Primary Containment Penetrations		4.6.4
SRV Penetration Fatigue Analysis	§54.21(c)(1)(i)	4.6.4.1
TAP Penetrations Fatigue Analyses	§54.21(c)(1)(i) §54.21(c)(1)(ii)	4.6.4.2
SRV Supports Fatigue Analyses	§54.21(c)(1)(i)	4.6.5
Main Steam Piping Penetration Bellows Cycle Limits	§54.21(c)(1)(i)	4.6.6
ERV Bellows Cycle Limits	§54.21(c)(1)(i)	4.6.7
Spent Fuel Pool Liner Fatigue Analysis	§54.21(c)(1)(i)	4.6.8
Spent Fuel Pool Storage Rack Fatigue Analysis	§54.21(c)(1)(i)	4.6.9
OTHER PLANT-SPECIFIC ANALYSES		4.7
Reactor Vessel and Reactor Vessel Head Flaw Evaluations		4.7.1
Reactor Vessel Flaw Evaluations	§54.21(c)(1)(iii)	4.7.1.1
Reactor Vessel Closure Head Flaw Evaluations	§54.21(c)(1)(iii)	4.7.1.2
Reactor Water Cleanup System Weld Overlay Fatigue Flaw Growth Evaluations	§54.21(c)(1)(iii)	4.7.2
Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking"	§54.21(c)(1)(iii)	4.7.3
Valve Fatigue Analyses		4.7.4
Feedwater Isolation Check Valves Fatigue Analysis	§54.21(c)(1)(i)	4.7.4.1
Emergency Condenser Isolation Valves Fatigue Analysis	§54.21(c)(1)(i)	4.7.4.2
Emergency Condenser Condensate Return Check Valves Fatigue Analysis	§54.21(c)(1)(i)	4.7.4.3

TABLE 4.1-2
SUMMARY OF RESULTS – NMP1 TIME-LIMITED AGING ANALYSES

TLAA DESCRIPTION	DISPOSITION	SLRA SECTION
ERV Vacuum Breaker Valve Fatigue Analysis	§54.21(c)(1)(i)	4.7.5
Core Spray System Weld Fatigue Flaw Growth Analysis	§54.21(c)(1)(i)	4.7.6
CRD Bottom Head Penetrations Fracture Mechanics Analysis	§54.21(c)(1)(ii)	4.7.7
Crane Cyclic Loading Analyses	§54.21(c)(1)(i)	4.7.8
Core Shroud Tie Rod X-750 Inconel Component Service Life	§54.21(c)(1)(iii)	4.7.9

4.2 REACTOR PRESSURE VESSEL AND INTERNALS NEUTRON EMBRITTLEMENT ANALYSES

Reactor Pressure Vessel (RPV) Embrittlement TLAAAs

10 CFR 50.60 (Reference 4.8.7) requires that all light-water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H (References 4.8.8 and 4.8.9). 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 cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant).

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 RPV 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 a decrease in the USE of RPV steels. This means greater temperatures are required for the material to behave in a ductile manner.

To reduce the potential for brittle fracture during reactor pressure vessel operation, changes in material toughness as a function of neutron radiation exposure (fluence) are accounted for through the use of operating P-T limits that are managed using a P-T Limits Report (PTLR). The P-T limits account for the decrease in material toughness of the RPV beltline and extended beltline materials associated with a given fluence. Pressure -Temperature limit curves are generated to provide minimum temperature limits that must be achieved during operations prior to application of specified RPV pressures. The P-T limit curves are based, in part, upon adjusted reference temperature (ART) values for each material located within the beltline region of the RPV. The ART value is computed using the initial RT_{NDT} (nil-ductility temperature) and ΔRT_{NDT} (change in nil-ductility temperature due to fluence) computed for the licensed operating period, along with appropriate margins.

The beltline and extended beltline regions include the RPV plates, welds and forging materials that are predicted to receive a cumulative neutron exposure of $1.0E+17$ neutrons/cm² through the end of the subsequent period of extended operation (SPEO). Since the cumulative neutron fluence will increase during the SPEO, a review is required to determine if any additional components will exceed the threshold value and require evaluation for neutron embrittlement.

Based on the projected drop in toughness for each beltline material as a result of exposure to the predicted fluence values, USE calculations are performed to determine if the components will continue to have adequate fracture toughness at the end of the license to meet the required minimums. Where the USE value for beltline

materials does not meet the required minimum value, an equivalent margins analysis (EMA) is performed. The RPV material ART and USE values, calculated on the basis of neutron fluence, as well as the P-T limit curves based on the ART values, are part of the licensing basis and support safety determinations and therefore have been identified as TLAAs. The increases in RT_{NDT} (ΔRT_{NDT}) also affect the bases for relief from circumferential weld inspection and the supporting calculation of limiting axial weld conditional failure probability. Therefore, these calculations have been identified as TLAAs.

The following TLAAs related to neutron embrittlement of the RPV are evaluated in the SLRA subsections listed below:

- Reactor Pressure Vessel Neutron Fluence Analyses (Section 4.2.1.1)
- Reactor Pressure Vessel Upper-Shelf Energy (USE) Analyses (Section 4.2.2)
- Reactor Pressure Vessel Adjusted Reference Temperature (ART) Analyses (Section 4.2.3)
- Reactor Pressure Vessel Pressure–Temperature (P-T) Limits (Section 4.2.4)
- Reactor Pressure Vessel Circumferential Weld Failure Probability Analyses (Section 4.2.5)
- Reactor Pressure Vessel Axial Weld Failure Probability Analyses (Section 4.2.6)

Reactor Vessel Internal Component Fluence TLAAs

Several RPV internal components have been analyzed for loss of preload due to irradiation enhanced stress relaxation due to neutron fluence and other aging mechanisms, which have also been identified as TLAAs that are evaluated in the SLRA subsections listed below:

- Reactor Pressure Vessel Internals Neutron Fluence Analyses (Section 4.2.1.2)
- Core Shroud Stabilizer Assembly Preload Relaxation Analysis (Section 4.2.7)

Comparison to Neutron Embrittlement TLAAs Evaluated During the First License Renewal

During the first license renewal project, including the license renewal application (LRA) and subsequent responses to Requests for Additional Information (RAIs), each of the TLAAs associated with RPV neutron embrittlement listed above for Sections 4.2.1 through 4.2.6 were identified and evaluated for 60 years. The same method used to evaluate these TLAAs in the first license renewal project has been used to re-evaluate them for 80 years in this application. First, the neutron fluence values have been projected for 80 years, as described in Section 4.2.1. Then, the 80-year fluence values have been used as inputs in updated analyses for each of the TLAAs (except P-T limits) and the resulting 80-year values have been compared to acceptance criteria, as applicable. Updated P-T Limits are not included in the SLRA but will be

developed prior to the expiration of the current P-T limits, consistent with the guidance provided in Section 4.2.2.1.4.3, NUREG-2192, Revision 1 (Reference 4.8.3).

The RPV internals neutron embrittlement TLAAAs listed above have been evaluated, as described in Section 4.2.7 based upon 80-year fluence projections described in Section 4.2.1.2.

4.2.1 NEUTRON FLUENCE ANALYSES

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter (flux) that contact the RPV shell and its internal components over a given period of time. 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 loss of fracture toughness aging effect resulting from neutron fluence.

The transport calculations for Nine Mile Point Nuclear Station, Unit 1 (NMP1) were carried out in R- θ and R-Z geometry using the Two-Dimensional Discrete Ordinates Code (DORT) and the BUGLE-96 cross-section library. The DORT code is an update of the DOT code which has been in use for this type of analysis for many years. The BUGLE-96 library is a 47-energy group ENDF/B-VI based data set produced specifically for light water reactor applications (an update of the earlier SAILOR library).

Analysis above and below the active fuel length was carried out using the Three-Dimensional Transport Code (TORT). The TORT code uses the same methodology as the DORT code except for the extension into the third dimension. These transport codes have been used in developing the 80-year fluence projections and associated RPV embrittlement analyses.

NMP1 Power Level Background

Below is a summary of NMP1 historical operating power levels which have been considered in developing the 80-year fluence projections:

- The original licensed thermal power (OLTP) level for NMP1 was 1538 megawatts thermal (MWt).
- The NRC authorized an increase in the maximum thermal power level from 1538 MWt to the current licensed thermal power (CLTP) level of 1850 MWt via Amendment No. 2, issued March 3, 1971 (Reference 4.8.11).

The current power level of 1850 MWt is the maximum power level evaluated for the SPEO. Eighty-year fluence projections for the NMP1 RPV are used in evaluating the neutron embrittlement TLAAs in SLRA Sections 4.2.2 through 4.2.7.

4.2.1.1 REACTOR PRESSURE VESSEL NEUTRON FLUENCE ANALYSES

TLAA Description:

Fluence projections developed using the NRC approved Discrete Ordinate Transfer (DORT) methodology have been used as inputs in the current licensing basis RPV neutron embrittlement analyses for the Nine Mile Point Nuclear Station, Unit 1 (NMP1) beltline components, including analyses of upper shelf energy (USE), adjusted reference temperatures (ART), pressure-temperature (P-T) limits, and axial and circumferential weld failure probability. These projections were developed for 60 years and 46 effective full power years (EFPY) and were submitted in 2017 for updated P-T limit curves. Fluence projections for 80 years at a projected 67 EFPY have been developed to evaluate the neutron fluence dependent TLAAAs associated with RPV in SLRA Sections 4.2.2 through 4.2.6.

TLAA Evaluation:

The first step in updating fluence projections from 60 years to 80 years was to update the EFPY projections, based upon past power history records, including capacity factors and power production data. In order to determine the number of EFPY applicable for 80 years, a review of cumulative neutron exposure and EFPY through recent completed operating cycles was performed.

The fluence projections have been developed by first compiling cumulative fluence resulting from each past operating cycle and then adding the predicted fluence for future operating cycles through the subsequent period of extended operation (SPEO). As of March 13, 2023, Unit 1 accumulated 40.27 EFPY at the end of the Unit's 25th operating cycle. Therefore, Unit 1 is projected to reach 66.71 EFPY in 80 years assuming the unit operates at 100 percent capacity starting in operating cycle 26 until August 2049. Based upon the review, 67 EFPY was determined to be a conservative value to use in projecting the 80-year fluence values to be used in evaluating the neutron embrittlement TLAAAs in Sections 4.2.2 through 4.2.7 of the SLRA.

For NMP1, the upper edge of the beltline at 67 EFPY will extend to elevation 373.9 inches above vessel zero, as compared to 371.3 inches at 46 EFPY. The lower edge of the beltline at 67 EFPY will extend down to 193.5 inches above vessel zero, as compared to 194.3 inches at 46 EFPY.

There are three additional RPV plates, upper intermediate course #1 (G-8-2), upper intermediate course #2 (G-9-R1), upper intermediate course #3 (G-8-9), and one additional weld, lower intermediate-upper intermediate circumferential weld #1-572 (RVWD-101), added to the beltline of Unit 1 at 67 EFPY.

The 67 EFPY fluence projections are provided in the following table:

1. SLRA Table 4.2.1.1-1, "Fluence Values for NMP1 RPV Materials with Fluence Over 1.0×10^{17} n/cm² (E > 1.0 MeV) at 67 EFPY."

These 67 EFPY fluence projections will be validated by the Neutron Fluence Monitoring (B.3.1.2) program during the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The NMP1 RPV beltline component fluence analyses have been satisfactorily projected through the subsequent period of extended operation. They are to be used as inputs in the RPV neutron embrittlement TLAA evaluations in Sections 4.2.2 through 4.2.6.

Table 4.2.1.1-1
Fluence Values for NMP1 RPV Materials with Fluence Over 1.0×10^{17} n/cm² (E > 1.0 MeV) at 67 EFPY

Beltline Component	Peak I.D. Fluence n/cm²	1/4T Fluence (1) n/cm²
Upper Intermediate Course #1 (G-8-2)	1.23E+17	8.02E+16
Upper Intermediate Course #2 (G-9-R1)	1.23E+17	8.02E+16
Upper Intermediate Course #3 (G-8-9)	1.23E+17	8.02E+16
Lower Intermediate Course #1 (G-307-3)	3.23E+18	2.11E+18
Lower Intermediate Course #2 (G-307-10)	3.23E+18	2.11E+18
Lower Intermediate Course #3 (G-307-4)	3.23E+18	2.11E+18
Lower Course #1 (G-8-1)	2.07E+18	1.35E+18
Lower Course #2 (G-8-3)	2.07E+18	1.35E+18
Lower Course #3 (G-8-4)	2.07E+18	1.35E+18
Lower Intermediate Course Vertical Welds (2-564 A/C)	3.18E+18	2.07E+18
Lower Course Vertical Welds (2-564 D/F)	2.11E+18	1.38E+18
Lower Intermediate-Upper Intermediate Circ Weld (1-572)	1.30E+17	8.48E+16
Lower-Lower Intermediate Circ Weld (3-564)	2.11E+18	1.38E+18

Note:

1. Attenuation Factor of 0.652

4.2.1.2 REACTOR PRESSURE VESSEL INTERNALS NEUTRON FLUENCE ANALYSES

TLAA Description:

Neutron fluence exposure has been used as an input in analyses of the Nine Mile Point Nuclear Station, Unit 1 (NMP1) RPV internals components. Since the neutron fluence exposure is time dependent, these analyses have been identified as TLAAAs that require evaluation for the subsequent period of extended operation (SPEO). Fluence projections for 80 years at a projected 67 effective full power years (EFPY) have been developed to evaluate the neutron fluence dependent TLAAAs associated with RPV internals components in SLRA Section 4.2.7.

TLAA Evaluation:

The core region transport calculations were carried out using the two-dimensional Discrete Ordinates Code (DORT) and the BUGLE-96 cross section library. Analysis above and below the active fuel length was carried out using the Three-Dimensional Transport Code (TORT). The TORT code uses the same methodology as the DORT code except for the extension into the third dimension. These transport codes have been used in developing the 80-year fluence projections and associated RPV embrittlement analyses.

The 80-year fluence projections for RPV internal components are provided in the following table.

- SLRA Table 4.2.1.2-1, “NMP1 Maximum RPV Internal Component Fluence Projections 67 EFPY Fluence.”

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The NMP1 reactor vessel internal component fluence analyses have been satisfactorily projected through the subsequent period of extended operation. They are to be used as inputs in the RPV internal components fluence-related TLAA evaluations in Section 4.2.7.

Table 4.2.1.2-1 NMP1 Maximum RPV Internal Component Fluence Projections 67 EFPY Fluence	
Component	Unit 1 Fluence (E> 1.0 MeV) n/cm ²
Core Shroud Repair Hardware Tie-Rod Upper Spring Assemblies	1.64E+19
Core Shroud Repair Hardware Tie-Rod Lower Spring Assemblies	1.82E+19

4.2.2 REACTOR PRESSURE VESSEL UPPER-SHELF ENERGY (USE) ANALYSES

TLAA Description:

Appendix G of 10 CFR 50 (Reference 4.8.8), Paragraph IV.A.1.a, states that RPV beltline materials must have a Charpy upper-shelf energy of no less than 75 ft-lb initially and must maintain a Charpy upper-shelf energy (USE) throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) RPV was designed and fabricated prior to the current requirements going into effect, and as a result, there is insufficient data available to establish the unirradiated USE value for beltline and extended beltline materials. As such, equivalent margin analysis (EMA) is used for all NMP1 beltline and extended beltline materials lacking unirradiated USE values. The EMA is also performed for all applicable USE beltline plate and weld materials for NMP1 that cannot satisfy the 50 ft-lb criterion. The current EMA analysis conservatively uses the existing acceptance criteria defined in BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal," which are the maximum allowable percent decrease in USE for the BWR/2 plates and BWR/2-6 welds. Where initial unirradiated USE values are available, the material is evaluated in accordance with NRC Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," (Reference 4.8.14) using the equations in NRC RG 1.162, "Format and Content of Report for Thermal Annealing Reactor Pressure Vessels," (Reference 4.8.13), which model the Charpy USE decrease curves. Since the EMA values determined to evaluate USE for 60 years are based upon the 54 effective full power years (EFPY) fluence values of BWRVIP-74-A, these analyses have been identified as TLAAs requiring evaluation for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

To evaluate USE for 80 years, the 67 EFPY fluence values described in Section 4.2.1 for reactor beltline and extended beltline materials have been used to develop revised EMA values that have been compared to the applicable design limits from BWRVIP-74-A.

- SLRA Table 4.2.2-1 summarizes the 80-year percent drop in USE for the NMP1 reactor vessel materials. All materials are shown to be acceptable with respect to the design limits.
- SLRA Table 4.2.2-2 provides the bounding 67 EFPY EMA for the limiting NMP1 Plate G-307-4 (Heat No. P2076-1).
- SLRA Table 4.2.2-3 provides the bounding 67 EFPY EMA for the limiting NMP1 Weld 2-564 A/C (Heat No. 86054B).
- SLRA Table 4.2.2-4 provides the bounding 67 EFPY EMA for the limiting NMP1 Weld 2-564 A/C (Heat No. 1248).

- SLRA Table 4.2.2-5 provides the 67 EFPY EMA for the NMP1 Plate G-307-10 (Heat No. P2091-2).
- SLRA Table 4.2.2-6 provides the 67 EFPY EMA for the NMP1 Plate G-8-1 (Heat No. P2112-1).
- SLRA Table 4.2.2-7 provides the 67 EFPY EMA for the NMP1 Plate G-8-2 (Heat No. P2106-1).
- SLRA Table 4.2.2-8 provides the 67 EFPY EMA for the NMP1 Plate G-9-R1 (Heat No. P2196-2).
- SLRA Table 4.2.2-9 provides the 67 EFPY EMA for the NMP1 Plate G-8-9 (Heat No. P2161-2).
- SLRA Table 4.2.2-10 provides the 67 EFPY EMA for the NMP1 Weld 1-572 (Heat No. 1248)

The USE values for NMP1 reactor vessel beltline and extended beltline materials have been satisfactorily evaluated for the SPEO based upon the updated EMA values determined using 80-year (67 EFPY) fluence projections.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The RPV USE analyses for NMP1 have been satisfactorily projected through the subsequent period of extended operation.

Table 4.2.2-1
NMP1 USE Assessment for 67 EFPY with 1/4T Fluence

	Description	ID No.	Heat No./ Flux No.	%Cu ⁽²⁾	Unirradiated USE ⁽¹⁾ (ft-lbs)	67 EFPY 1/4T Fluence ⁽²⁾ (n/cm ²)	% Drop in USE ⁽³⁾	USE at 1/4T (ft-lbs)	Requires EMA
Plates	<i>Extended Beltline Materials</i>								
	Upper Intermediate Course #1	G-8-2	P2106-1	0.35	EMA ⁽⁴⁾	8.02E+16	14.0	N/A	YES
	Upper Intermediate Course #2	G-9-R1	P2196-2	0.35	EMA ⁽⁴⁾	8.02E+16	14.0	N/A	YES
	Upper Intermediate Course #3	G-8-9	P2161-2	0.35	EMA ⁽⁴⁾	8.02E+16	14.0	N/A	YES
	<i>Beltline Materials</i>								
	Lower Intermediate Course #1	G-307-3	P2074-2	0.20	65.0	2.11E+18	20.1	51.96	NO
	Lower Intermediate Course #2	G-307-10	P2091-2	0.22	63.1	2.11E+18	21.4	49.57	YES
	Lower Intermediate Course #3	G-307-4	P2076-1	0.27	52.0	2.11E+18	24.9	39.05	YES
	Lower Course #1	G-8-1	P2112-1	0.236	53.3	1.35E+18	20.3	42.49	YES
	Lower Course #2 ⁽⁵⁾	G-8-3	P2130-1	Note (7)	64	1.35E+18	16.6	53.40	NO
	Lower Course #3 ⁽⁵⁾	G-8-4	P2130-2	Note (7)	64	1.35E+18	16.6	53.40	NO
Welds	<i>Beltline Materials</i>								
	Lower Intermediate Course Vertical Welds	2-564 A/C	86054B/4E5F	0.214	90	2.07E+18	24.4	68.05	NO
	Lower Intermediate Course Vertical Welds	2-564 A/C	1248/4K13F	0.214	90	2.07E+18	24.4	68.05	NO
	Lower Course Vertical Welds	2-564 D/F	86054B/4E5F	0.214	90	1.38E+18	22.1	70.08	NO
	Lower-Lower Intermediate Circ Weld	3-564	1248/4M2F	0.214	90	1.38E+18	22.1	70.08	NO
	<i>Extended Beltline Material</i>								
	Lower Intermediate-Upper Intermediate Circ Weld	1-572	1248/3576	0.214	EMA ⁽⁴⁾	8.48E+16	11.4	N/A	YES
ISP	Plate ⁽⁶⁾	N/A	C1079-1	0.22	N/A	N/A	N/A	N/A	N/A
	Weld ⁽⁶⁾	N/A	51912	0.13	N/A	N/A	N/A	N/A	N/A
	SSP Plate ⁽⁵⁾	N/A	P2130-2	0.172	68.2	1.35E+18	17.6	56.20	NO

Notes:

- Unirradiated USE values were not available for all beltline materials.
- Cu content and 1/4T fluence values are obtained from SLRA Table 4.2.3-1
- % Drop in USE calculated by Equation 14 from NRC RG 1.162 (Reference 4.8.13)
- Equivalent margin assessment (EMA) for these heats is performed in accordance with BWRVIP-74-A.
- % Drop in USE of Lower Course #2 and #3 plates is based per NRC RG 1.99, Revision 2, (Reference 4.8.14) Position 1.2 whereas the matching SSP plate is based per NRC RG 1.99, Position 2.2, noting discrepancy in unirradiated USE.
- Chemical properties of the ISP material are indicated but not considered for EMA due to lack of heat number match.
- Proprietary Value from BWRVIP-135, Revision 4, Table D-2.

Table 4.2.2-2 Bounding 67 EFPY EMA for NMP1 Plate Material (Heat No. P2076-1) NMP1 Plate G-307-4 BWR/2 Plate	
Surveillance Plate USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate (Heat P2076-1, Lower Intermediate Course #3) USE:	
%Cu	= 0.27
67 EFPY Peak ID Fluence	= 3.23E+18 n/cm ²
67 EFPY 1/4T Fluence	= 2.11E+18 n/cm ²
RG 1.99 Predicted % Decrease	= 24.9 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
24.9% ≤ design limit from BWRVIP-74-A ⁽¹⁾	
Therefore, this vessel plate is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-3 Bounding 67 EFPY EMA for NMP1 Weld Material (Heat No. 86054B) NMP1 Weld 2-564 A/C BWR/2-6 Weld	
Surveillance Weld USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Weld (Heat 86054B, Lower Intermediate Course Vertical Welds) USE:	
%Cu	= 0.214
67 EFPY Peak ID Fluence	= 3.18E+18 n/cm ²
67 EFPY 1/4T Fluence	= 2.07E+18 n/cm ²
RG 1.99 Predicted % Decrease	= 24.4 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
24.4% ≤ design limit from BWRVIP-74-A ⁽¹⁾	
Therefore, this vessel weld is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-4 Bounding 67 EFPY EMA for NMP1 Weld Material (Heat No. 1248) NMP1 Weld 2-564 A/C BWR/2-6 Weld	
Surveillance Weld USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Weld (Heat 1248, Lower Intermediate Course Vertical Welds) USE:	
%Cu	= 0.214
67 EFPY Peak ID Fluence	= $3.18\text{E}+18$ n/cm ²
67 EFPY 1/4T Fluence	= $2.07\text{E}+18$ n/cm ²
RG 1.99 Predicted % Decrease	= 24.4 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
$24.4\% \leq \text{design limit from BWRVIP-74-A}^{(1)}$	
Therefore, this vessel weld is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-5 67 EFPY EMA for NMP1 Plate Material (Heat No. P2091-2) NMP1 Plate G-307-10 BWR/2 Plate	
Surveillance Plate USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Beltline Plate (Heat P2091-2, Lower Intermediate Course #2) USE:	
%Cu	= 0.22
67 EFPY Peak ID Fluence	= $3.23\text{E}+18 \text{ n/cm}^2$
67 EFPY 1/4T Fluence	= $2.11\text{E}+18 \text{ n/cm}^2$
RG 1.99 Predicted % Decrease	= 21.4 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
$21.4\% \leq \text{design limit from BWRVIP-74-A}^{(1)}$	
Therefore, this vessel plate is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-6 67 EFPY EMA for NMP1 Plate Material (Heat No. P2112-1) NMP1 Plate G-8-1 BWR/2 Plate	
Surveillance Plate USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Beltline Plate (Heat P2112-1, Lower Course #1) USE:	
%Cu	= 0.236
67 EFPY Peak ID Fluence	= 2.07+18 n/cm ²
67 EFPY 1/4T Fluence	= 1.35E+18 n/cm ²
RG 1.99 Predicted % Decrease	= 20.3 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
20.3% ≤ design limit from BWRVIP-74-A ⁽¹⁾	
Therefore, this vessel plate is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-7 67 EFPY EMA for NMP1 Plate Material (Heat No. P2106-1) NMP1 Plate G-8-2 BWR/2 Plate	
Surveillance Plate USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Extended Beltline Plate (Heat P2106-1, Upper Intermediate Course #1) USE:	
%Cu	= 0.35
67 EFPY Peak ID Fluence	= 1.23E+17 n/cm ²
67 EFPY 1/4T Fluence	= 8.02E+16 n/cm ²
RG 1.99 Predicted % Decrease	= 14.0 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
14.0%	≤ design limit from BWRVIP-74-A ⁽¹⁾
Therefore, this vessel plate is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-8 67 EFPY EMA for NMP1 Plate Material (Heat No. P2196-2) NMP1 Plate G-9-R1 BWR/2 Plate	
Surveillance Plate USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Extended Beltline Plate (Heat P2196-2, Upper Intermediate Course #2) USE:	
%Cu	= 0.35
67 EFPY Peak ID Fluence	= 1.23E+17 n/cm ²
67 EFPY 1/4T Fluence	= 8.02E+16 n/cm ²
RG 1.99 Predicted % Decrease	= 14.0 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
14.0%	≤ design limit from BWRVIP-74-A ⁽¹⁾
Therefore, this vessel plate is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-9 67 EFPY EMA for NMP1 Plate Material (Heat No. P2161-2) NMP1 Plate G-8-9 BWR/2 Plate	
Surveillance Plate USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Extended Beltline Plate (Heat P2161-2, Lower Intermediate Course #3) USE:	
%Cu	= 0.35
67 EFPY Peak ID Fluence	= 1.23E+17 n/cm ²
67 EFPY 1/4T Fluence	= 8.02E+16 n/cm ²
RG 1.99 Predicted % Decrease	= 14.0 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
14.0%	≤ design limit from BWRVIP-74-A ⁽¹⁾
Therefore, this vessel plate is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

Table 4.2.2-10 67 EFPY EMA for NMP1 Weld Material (Heat No. 1248) NMP1 Weld 1-572 BWR/2-6 Weld	
Surveillance Weld USE:	
%Cu	= N/A
1 st Capsule Fluence	= N/A
1st Capsule Measured % Decrease	= N/A (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	= N/A (RG 1.99, Rev. 2, Figure 2)
Extended Beltline Weld (Heat 1248, Lower Intermediate – Upper Intermediate Circ Weld) USE:	
%Cu	= 0.214
67 EFPY Peak ID Fluence	= 1.30E+17 n/cm ²
67 EFPY 1/4T Fluence	= 8.48E+16 n/cm ²
RG 1.99 Predicted % Decrease	= 11.4 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	= N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:	
11.4%	≤ design limit from BWRVIP-74-A ⁽¹⁾
Therefore, this vessel weld is bounded by Equivalent Margin Analysis	

Note:

1. BWRVIP-74-A is proprietary.

4.2.3 REACTOR PRESSURE VESSEL ADJUSTED REFERENCE TEMPERATURE (ART) ANALYSES

TLAA Description:

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the pressure-temperature (P-T) limit curves to account for irradiation effects. NRC Regulatory Guide 1.99, Revision 2 (Reference 4.8.14) provides the methodology for determining the ART of the limiting materials. The initial nil-ductility reference temperature, RT_{NDT} , is the temperature at which an unirradiated ferritic steel material changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the ASME, Section III, Paragraph NB-2331. If RT_{NDT} is unavailable for extended beltline materials, it is determined in methods described in NRC Branch Technical Position (BTP) 5-3 (Reference 4.8.15). Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50, Appendix G (Reference 4.8.8) defines the fracture toughness requirements for the life of 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}) determines how much higher the vessel temperature must be raised for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + ΔRT_{NDT} + Margin. Since the ΔRT_{NDT} value is a function of 46 EFPY fluence in the current ART calculations associated with the 60-year licensed operating period, these ART analyses have been identified as TLAA's requiring evaluation for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

10 CFR 50, Appendix G requires the determination of ART values for reactor vessel beltline ferritic materials for the life of the plant. The beltline plates, axial welds, and circumferential welds are fabricated from ferritic materials.

As described in Section 4.2.1, 67 EFPY fluence values have been determined for Nine Mile Point Nuclear Station, Unit 1 (NMP1) beltline and extended beltline materials. The 1/4T fluence values for each location was derived from the inside surface (OT) fluence values based upon the fluence attenuation methods described in NRC Regulatory Guide 1.99, Revision 2.

Table 4.2.3-1 provides the NMP1 67 EFPY ART values computed for the extended beltline plates, beltline plates, axial and circumferential welds, and Integrated Surveillance Program (ISP) plates and welds. The NMP1 ISP plate and weld materials are from BWRVIP-135, Revision 4, "Integrated Surveillance Program (ISP) Data Source Book and Plant Evaluations," which supersedes plant-specific values where available, as required by BWR Integrated Surveillance Program procedures.

The limiting location is described below.

Unit 1 ART Results:

- The limiting ART value for the NMP1 RPV at 67 EFPY is 179.5 degrees F, which is computed for Lower Course #1 plate G-8-1.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The 67 EFPY NMP1 RPV ART analyses have been satisfactorily projected through the subsequent period of extended operation.

Table 4.2.3-1
NMP1 - 67 EFPY Adjusted Reference Temperature (ART) Values for Extended Beltline and Beltline Plates, Axial and Circumferential Welds, and Integrated Surveillance Program (ISP) Plates and Welds

Description	Component	Heat No./ Flux No.	% Cu	% Ni	CF	Initial RT _{NDT} (°F)	67 EFPY Fluence at 1/4T (n/cm ²)	Fluence Factor (f)	ΔRT _{NDT} (°F)	σ _A °F	σ _i °F	Margin (°F)	ART at 1/4T (°F)
Extended Beltline Plates													
Upper Intermediate Course #1	G-8-2	P2106-1	0.35	0.53	203.25	25.1	8.02E+16	0.094	19.1	9.6	0	19.1	63.4
Upper Intermediate Course #2	G-9-R1	P2196-2	0.35	0.52	202.00	32.7	8.02E+16	0.094	19.0	9.5	0	19.0	70.7
Upper Intermediate Course #3	G-8-9	P2161-2	0.35	0.48	197.00	26.5	8.02E+16	0.094	18.6	9.3	0	18.6	63.6
Beltline Plates													
Lower Intermediate Course #1	G-307-3	P2074-2	0.20	0.48	134.60	28	2.11E+18	0.582	78.3	17.0	0	34.0	140.3
Lower Intermediate Course #2	G-307-10	P2091-2	0.22	0.51	148.85	20	2.11E+18	0.582	86.6	17.0	0	34.0	140.6
Lower Intermediate Course #3	G-307-4	P2076-1	0.27	0.53	173.85	40	2.11E+18	0.582	101.2	17.0	0	34.0	175.2
Lower Course #1	G-8-1	P2112-1	0.236	0.503	228.35	36	1.35E+18	0.480	109.5	17.0	0	34.0	179.5
Lower Course #2 ⁽¹⁾	G-8-3	P2130-1	Note 3	Note 3	129.93	-3	1.35E+18	0.480	62.3	17.0	0	34.0	93.3
Lower Course #3 ⁽¹⁾	G-8-4	P2130-2	Note 3	Note 3	129.93	-3	1.35E+18	0.480	62.3	17.0	0	34.0	93.3
Beltline Welds													
Lower Intermediate Course Vertical Welds (RVWD 139, 140, 141)	2-564 A/C	86054B/ 4E5F	0.214	0.046	97.61	-50	2.07E+18	0.578	56.4	28.0	17	65.5	71.9
Lower Intermediate Course Vertical Welds (RVWD 139, 140, 141)	2-564 A/C	1248/4K13 F	0.214	0.076	99.93	-50	2.07E+18	0.578	57.8	28.0	17	65.5	73.3
Lower Course Vertical Welds (RVWD 142, 143, 144)	2-564 D/F	86054B/ 4E5F	0.214	0.046	97.61	-50	1.38E+18	0.484	47.2	23.6	17	58.2	55.4

Table 4.2.3-1
NMP1 - 67 EFPY Adjusted Reference Temperature (ART) Values for Extended Beltline and Beltline Plates, Axial and Circumferential Welds, and Integrated Surveillance Program (ISP) Plates and Welds

Description	Component	Heat No./ Flux No.	% Cu	% Ni	CF	Initial RT _{NDT} (°F)	67 EFPY Fluence at 1/4T (n/cm ²)	Fluence Factor (f)	ΔRT _{NDT} (°F)	σ _Δ °F	σ _i °F	Margin (°F)	ART at 1/4T (°F)
Lower-Lower Intermediate Circ Weld (RVWD 137)	3-564	1248/4M2F	0.214	0.076	99.93	-50	1.38E+18	0.484	48.3	24.2	17	59.1	57.4
Extended Beltline Weld													
Lower Intermediate- Upper Intermediate Circ Weld (RVWD 101)	1-572	1248/3576	0.214	1.200	254.00	-50	8.48E+16	0.098	24.9	12.4	17	42.1	17.0
ISP													
Surveillance Plate ⁽²⁾	Plate	C1079-1	0.22	0.51	148.85	40	2.11E+18	0.582	86.6	17	0	34.0	160.6
Surveillance Weld ⁽²⁾	Weld	51912	0.13	0.10	67.00	-50	2.07E+18	0.578	38.7	19.4	17	51.5	40.3
SSP ⁽¹⁾	Plate	P2130-2	0.172	0.584	146.80	-3	1.35E+18	0.480	70.4	8.5	0	17.0	84.4

Notes:

1. Due to the match in heat number, Vessel Plate ART is based per NRC RG 1.99, Revision 2, Position 1.1 whereas SSP plate material provides ART based per NRC RG 1.99, Revision 2, Position 2.1
2. The Surveillance material does not have a match in the observed RPV materials for this analysis. Results are informational only and not to be used for determination of the limiting ART material.
3. Proprietary Value from BWRVIP-135, Revision 4, Table D-2

4.2.4 REACTOR PRESSURE VESSEL PRESSURE-TEMPERATURE (P-T) LIMITS

TLAA Description:

10 CFR 50, Appendix G (Reference 4.8.8) requires that the RPV be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the minimum acceptable reactor coolant temperature as a function of reactor pressure. As the RPV is exposed to increased neutron irradiation over time, its fracture toughness is reduced. The P-T limits must account for the change in material properties due to anticipated RPV fluence.

The currently licensed P-T limit curves are located in the Pressure-Temperature Limits Report (PTLR). The currently licensed P-T curves were developed for up to 46 effective full power years (EFPY). Since the current P-T curves are based on 46 EFPY projections for the currently approved 60-year operating term, the P-T limit curves have been identified as TLAA's requiring evaluation for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

In accordance with NUREG-2192, Revision 1 (Reference 4.8.3), Section 4.2.2.1.4, for plants that have an approved PTLR, the P-T limits for the SPEO will be updated at the appropriate time through the plant's Administrative Section of the Technical Specifications and the plant's PTLR process. Nine Mile Point Nuclear Station, Unit 1 Technical Specification Section 6.6.7, "Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)" is the administrative section addressing the PTLR process. This process will ensure that the P-T limits for the SPEO will be updated prior to expiration of the 46 EFPY P-T limit curves. The analyses supporting the P-T curves consider all locations within the reactor coolant pressure boundary as they do in the current P-T curves. Maintenance of the P-T limits during the SPEO will be managed using the PTLR process as described above.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) of the NMP1 RPV will be adequately managed through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). Pressure-Temperature limits will be updated prior to 46 EFPY in accordance with the Administrative Section of the Technical Specifications.

4.2.5 REACTOR PRESSURE VESSEL CIRCUMFERENTIAL WELD FAILURE PROBABILITY ANALYSIS

TLAA Description:

Nine Mile Point Nuclear Station, Unit 1 (NMP1) has previously applied for and been granted relief from reactor pressure vessel (RPV) circumferential weld inspections, as described in an NRC Safety Evaluation Report (SER) dated August 3, 2009 (Reference 4.8.17).

The recommendations for inspection of RPV shell welds in BWRVIP-05, “BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations,” provide inspection recommendations for RPV axial welds and circumferential welds. NRC Generic Letter (GL) 98-05, (Reference 4.8.18) informed BWR licensees that they may request relief from the requirement to inspect circumferential welds by demonstrating that, at the expiration of their license, the circumferential welds will continue to satisfy the limiting conditional failure probability for circumferential welds in the NRC SER (Reference 4.8.19) that evaluated BWRVIP-05.

Subsequently, BWRVIP-329-A, “Updated Probabilistic Fracture Mechanics Analyses for BWR RPV Welds to Address Extended Operations,” approved in December 2021, and the associated NRC SER provide additional technical basis for reduction in inspection of RPV circumferential welds and an assessment of axial weld integrity for extended operations of up to 80 years. Section 5.0 of BWRVIP-329-A provides criteria for applicability based on plant-specific data.

Since the current circumferential weld failure probability analysis for NMP1, that was included in the 2009 relief request (Reference 4.8.17), is based upon 46 effective full power years (EFPY) fluence values associated with 60 years of operation, this analysis has been identified as a TLAA requiring evaluation for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

Plant-specific RPV dimensions and material chemistry for NMP1 were evaluated for the applicability criteria in BWRVIP-329-A, Section 5.0. This confirmed that the NMP1 RPV is within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

The limiting maximum reference temperatures (RT_{MAX}) at 67 EFPY were calculated using plant-specific material chemistry, initial unirradiated RT_{NDT} , and projected 80-year fluence values for the NMP1 RPV plates and welds. The end-of-interval (EOI) is defined as 80 years, which is equivalent to 67 EFPY for neutron fluence. The EOI RT_{MAX} values for all NMP1 plates and welds meet the acceptability criteria for the limiting plates, circumferential welds, and axial welds in BWRVIP-329-A. Therefore, this evaluation shows that the NMP1 RPV meets the acceptance criteria of BWRVIP-329-A, Section 5.0.

Reapplication for relief from RPV circumferential weld examinations will be made in accordance with 10 CFR 50.55(a)(z)(1) for NRC review and approval prior to exceeding 46 EFPY. The plant-specific information described above demonstrates that at the end of the SPEO, the circumferential beltline weld materials meet the limiting conditional failure probability for circumferential welds specified in the NRC's

final SER of BWRVIP-329-A.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The NMP1 RPV circumferential weld failure probability analysis has been successfully evaluated through the subsequent period of extended operation, using the latest NRC approved methodology. Relief from inspection of circumferential welds will be requested through a reapplication under the 10 CFR 50.55a process.

4.2.6 REACTOR PRESSURE VESSEL AXIAL WELD FAILURE PROBABILITY ANALYSES

TLAA Description:

The recommendations for inspection of reactor pressure vessel (RPV) shell welds in BWRVIP-05 include examination recommendations of BWR RPV axial welds. Nine Mile Point Nuclear Station, Unit 1 (NMP1) successfully evaluated axial weld failure probabilities for 60-years of operation at 46 EFPY, as described in an NRC Safety Evaluation Report (SER) dated August 3, 2009 (Reference 4.8.17).

Subsequently, BWRVIP-329-A, “Updated Probabilistic Fracture Mechanics Analyses for BWR RPV Welds to Address Extended Operations,” approved in December 2021, and the associated NRC SER provide additional technical basis for an assessment of axial weld integrity for extended operations of up to 80 years. Section 5.0 of BWRVIP-329-A, “BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations,” provides criteria for applicability based on plant-specific data.

Since these failure probability assessments are applicable to NMP1 and the current axial weld failure probability analysis for NMP1, that was included in the 2009 relief request (Reference 4.8.17), is based upon 46 effective full power years (EFPY) fluence values associated with 60 years of operation, these have been identified as a TLAA requiring evaluation through the subsequent period of extended operation (SPEO).

TLAA Evaluation:

Plant-specific RPV dimensions and material chemistry for NMP1 were evaluated for the applicability criteria in BWRVIP-329-A, Section 5.0. This confirmed that the NMP1 RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

The limiting maximum reference temperatures (RT_{MAX}) at 67 EFPY were calculated using plant-specific material chemistry, initial unirradiated RT_{NDT} , and projected 80-year fluence values for the NMP1 RPV plates and welds. The end-of-interval (EOI) is defined as 80 years, which is equivalent to the 67 EFPY for neutron fluence. The EOI RT_{MAX} values for all NMP1 RPV plates and welds meet the acceptability criteria for the limiting plates, circumferential welds, and axial welds in BWRVIP-329-A. Therefore, this evaluation shows that the NMP1 RPV meets the acceptance criteria of BWRVIP-329-A, Section 5.0.

The plant-specific information described above demonstrates that at the end of the SPEO, the axial beltline weld materials meet the limiting conditional failure probability for axial welds specified in the NRC’s final SER of BWRVIP-329-A.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The NMP1 RPV axial weld failure probability analysis has been projected through the subsequent period of extended operation using the latest NRC approved methodology.

4.2.7 CORE SHROUD STABILIZER ASSEMBLY PRELOAD RELAXATION ANALYSIS

TLAA Description:

Inservice inspections identified indications in and near the heat-affected zone of the core shroud horizontal and vertical welds caused by intergranular stress corrosion cracking (IGSCC). A core shroud repair was designed to structurally replace the core shroud's horizontal welds H1 through H7 and was installed in 1995. The design consists of four shroud stabilizer tie-rod assemblies combined with core plate wedges, which were installed approximately 90 degrees apart in the core shroud/reactor pressure vessel annulus, between attachment points at the top of the upper core shroud head flange and the core shroud conical support. Each tie-rod assembly consists of a tie-rod, upper support, upper spring, middle support, lower lateral and axial springs, and lower support.

The design of the shroud stabilizer tie-rod assemblies accounted for a preload relaxation of five percent for the upper and lower springs due to an end-of-life fluence threshold.

Since the tie-rod assemblies are subject to a loss of preload within the design life, tie-rod preload relaxation due to neutron fluence has been identified as a TLAA that requires evaluation for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

For the SLRA, fluence projections were prepared for 80-years at 67 effective full power years (EFPY), using the methodology described in SLRA Section 4.2.1. The maximum 67 EFPY exposure to the shroud stabilizer upper spring assemblies is $1.64\text{E}+19$ n/cm² and $1.82\text{E}+19$ n/cm² for the lower spring assemblies, which is less than the fluence assumed in the original design. Therefore, the fluence projection assumed in the original design is valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The core shroud stabilizer tie-rod assemblies preload relaxation due to fluence exposure has been demonstrated to remain valid through the subsequent period of extended operation.

4.3 METAL FATIGUE ANALYSES

Fatigue analyses are required on components designed to ASME, Section III, Class 1 and Class MC. In addition, other codes such as ASME Section III, Class 2 and 3, and ASA (ANSI) B31.1 may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. As described in SLRA Section 4.1, NUREG-2192, Revision 1 (Reference 4.8.3) also provides examples of components that are 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 Nine Mile Point Nuclear Station, Unit 1 (NMP1). Each of the potential TLAAs were evaluated against the six TLAA screening criteria specified in 10 CFR 54.3. Those that were identified as NMP1 fatigue TLAAs are evaluated using 80-year transient occurrence and cumulative usage projections, described in SLRA Section 4.3.1, and summarized in the following subsections:

- Reactor Vessel and Piping Fatigue Analyses (SLRA Section 4.3.2)
- Fatigue of the Emergency Condensers (SLRA Section 4.3.3)
- ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Analysis and HELB Exclusions of Recirculation Piping Analysis (SLRA Section 4.3.4)
- Environmentally Assisted Fatigue Analysis (SLRA Section 4.3.5)
- Reactor Vessel Internals Fatigue Analyses (SLRA Section 4.3.6)

4.3.1 TRANSIENT CYCLE AND CUMULATIVE USAGE PROJECTIONS FOR 80 YEARS

Fatigue analyses are based upon explicit numbers (occurrences) and amplitudes of thermal and pressure transients usually described in design specifications. 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 number of transient occurrences postulated to bound 60 years of service, making them a TLAA.

Projections of the transient occurrences through the subsequent period of extended operation (SPEO) were developed to determine whether the existing analyses remain valid for 80 years. These transient occurrences and projections are documented in SLRA Table 4.3.1-1.

SLRA Table 4.3.1-1 provides the results of the 80-year transient occurrence projections for Nine Mile Point Nuclear Station, Unit 1 (NMP1). The first column of the table provides the transient numbers. Note 1 provides the historical basis for the transients. The second column of the table provides the transient description, and the third column of the table lists the cumulative number of transient occurrences as of September 30, 2023. The fourth column in SLRA Table 4.3.1-1 shows the number of transient occurrences projected to occur over 80 years based on operating history, as described below. The fifth column in SLRA Table 4.3.1-1 lists the design transient occurrences, which are the assumed numbers of transient occurrences specified in the NMP1 design basis.

A review of Fatigue Monitoring (B.3.1.1) program data was performed to identify the number of cumulative transient occurrences for each transient type that occurred up to September 30, 2023. Since most nuclear power plants, including NMP1, have experienced a significant declining trend in accumulation of transients over time, transient occurrence projections based on recent operating experience provides an accurate basis for future projections. Therefore, for transients that have current occurrences greater than zero, the 80-year transient projections are based on a projected cycle accumulation rate. The projected cycle accumulation rate was determined by using a weighting factor of 0.75 for the most recent 10-year cycle accumulation rate and 0.25 for the overall occurrence accumulation rate (i.e., transient occurrence accumulation rate since the plant started operation).

The 80-year projected number of occurrences were determined by adding the number of past occurrences up to September 30, 2023, to the number of predicted future occurrences.

SLRA Table 4.3.1-1 shows that the transients “Turbine Roll and Increase to Rated Power” (transient number 5), “Reduction to 0% Power” (transient number 7), and “Hot Standby (Feedwater Cycling)” (transient number 8) 80-year projected transient occurrences in the fourth column of the table exceed the assumed number of original design transient occurrences in the fifth column. However, the assumed number of design transient occurrences does not represent a final design limit; rather, the design limit is that the cumulative usage factor (CUF) or environmentally adjusted cumulative usage factor (CUF_{en}) does not exceed a value of 1.0. Since the CUF or CUF_{en} of a component is computed as a function of multiple thermal and pressure transients, increasing the number of transient occurrences for one transient type to a value

greater than the number assumed in the fatigue analysis may not cause the CUF or CUF_{en} to exceed the design limit. For example, the transients “Turbine Roll and Increase to Rated Power” (transient number 5) and “Reduction to 0% Power” (transient number 7) are only assumed in the fatigue calculations of component number 8 (PIPE_FW) of SLRA Table 4.3.1-2 and the resulting 80-year CUF_{en} projection is significantly less than the limit of 1.0. “Hot Standby (Feedwater Cycling)” (transient number 8) is not considered in the CUF or CUF_{en} determination of any components listed in SLRA Table 4.3.1-2.

The transient “Hydrostatic Pressure Test” (transient number 27) was performed once, and no additional occurrences of this test are expected, such that the projected number of transient occurrences for this transient was assumed to be one over 80 years. For the transients “Single Relief Valve (SRV) Blowdown” (transient number 10), “Unisolation of an Isolated Loop 1” (transient number 13a), “Inadvertent Start of Cold Loop 1” (transient number 16a), “Loss of Feedwater Flow” (transient number 24), “Overpressure to 1,250 psig” (transient number 25), “Overpressure to 1,375 psig” (transient number 26), and “Operating Basis Earthquake (OBE)” (transient number 28) which have never occurred, the projected number of transient occurrences were assumed to be one over 80 years to ensure conservative CUF projections.

Consistent with Section X.M1 of NUREG-2191, Revision 1 (Reference 4.8.4), the Fatigue Monitoring (B.3.1.1) program monitors applicable station transients that cause cyclic strains and contribute to fatigue, as specified in the underlying component fatigue analyses, and monitors or validates appropriate environmental parameters that contribute to environmental fatigue correction factor (F_{en}) values.

The NMP1 first license renewal application committed to implementing the Fatigue Monitoring (B.3.1.1) program to include automated transient occurrence counting and automated calculation and tracking of fatigue CUFs. As a result, the SI:FatiguePro™ software was implemented at NMP1 in 2007. SI:FatiguePro™ is a computerized data acquisition, recording, thermal transient and cumulative fatigue usage tracking program.

The NMP1 SI:FatiguePro™ automated software uses temperature and pressure parameters, including the rates of changes of these parameters, to properly count and categorize transient occurrences and calculate CUFs for critical station components. The transient occurrences assigned by SI:FatiguePro™ are periodically reviewed to ensure all transient occurrences are correctly captured and assigned. This review also ensures that the cyclic load severities used in the fatigue parameter calculations remain bounding.

The number of occurrences and the severity of the station transients that contribute to the fatigue analyses for each component are monitored. SI:FatiguePro™ is used at NMP1 to determine the overall effect of the cumulative numbers of transient occurrences that have occurred at a given time and determines the CUF and CUF_{en} values for all monitored locations resulting from the combination of transient occurrences that have occurred during the period.

Prior to the first period of extended operation, NMP1 performed station-specific calculations for the applicable locations identified in NUREG/CR-6260 (Reference 4.8.20) for older-vintage BWR plants, to assess the potential effects of reactor coolant on component fatigue life. For these locations, CUF_{en} values are calculated and

tracked by the program. Actual station water chemistry conditions are periodically reviewed and compared to the conditions assumed in the environmentally assisted fatigue (EAF) calculations to confirm that the water chemistry parameters used to calculate the F_{en} values remain valid. The thermal zones and materials of fabrication associated with the limiting EAF locations, as further explained in SLRA Section 4.3.5, are documented in SLRA Table 4.3.1-2 columns three and four.

The bounding CUF and CUF_{en} locations at NMP1 are shown in the second column of SLRA Table 4.3.1-2. Eighty-year projections of CUF and CUF_{en} for the bounding locations at NMP1 are shown in the fifth and sixth columns of SLRA Table 4.3.1-2. Monitoring of the most limiting locations using SI:FatiguePro™ maintains assurance that all locations remain bounded and design limits for fatigue and EAF remain satisfied throughout the SPEO and allow for sufficient time to initiate actions when design limits are approached.

The CUF and CUF_{en} values for the components monitored by SI:FatiguePro™ are compared to appropriate acceptance criterion in the seventh column of SLRA Table 4.3.1-2 (e.g., 1.0). All projected 80-year CUF and CUF_{en} values in SLRA Table 4.3.1-2 meet the ASME Section III limit of 1.0. As long as the CUF values do not exceed the allowable values, the design limits remain satisfied. If monitored incremental CUF or CUF_{en} values exceed 80 percent of the limit, then the condition will be entered into the corrective action program and evaluated for corrective action to be taken prior to exceeding the design limit acceptance criterion.

The 80-year transient occurrence projections provided in SLRA Table 4.3.1-1 and the resulting 80-year CUF and CUF_{en} projections provided in SLRA Table 4.3.1-2, are used to evaluate the fatigue TLAAs in SLRA Sections 4.3, 4.6, and 4.7. The SI:FatiguePro™ software will monitor the transients provided in SLRA Table 4.3.1-1 in the SPEO.

Table 4.3.1-1
NMP1 – 80-Year Transient Occurrence Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Occurrences to-date (9/30/23)	80-Year Projected Transient Occurrences	Number of Design Transient Occurrences	UFSAR Sections and Tables
1	Unbolt (Vessel Head Removal)	29	44	50	Table V-2
2	Boltup (Vessel Head Reinstallation)	29	44	50	Table V-2
3	Design Pressure Test (Leak Test)	35	51	130	(Note 4)
4	Heatup - Normal Startup (100 °F/Hr)	173	218	240	Table V-2
5	Turbine Roll and Increase to Rated Power	271	330 (Note 2)	240	(Note 4)
6	Cooldown - Normal Shutdown (100 °F/Hr)	171	216	229	Table V-2
7	Reduction to 0% Power	163	207 (Note 2)	120	(Note 4)
8	Hot Standby (Feedwater Cycling)	719	813 (Note 2)	120	(Note 4)
9	300 °F/Hr Emergency Cooldown	1	2	10	Table V-2
9a	Core Spray Injection	1	2	NA	(Note 4)
10	Single Relief Valve (SRV) Blowdown	0	1	1	Table V-2
11	Scram	159	182	280	Table V-2
12	Emergency Condenser Initiation into Isolated Loop	2	3	30	Table V-2
13	Unisolation of an Isolated Loop	24	41	NA (Note 3)	Table V-2
13a	Unisolation of an Isolated Loop 1	0	1	30	Table V-2
13b	Unisolation of an Isolated Loop 2	6	7	30	Table V-2
13c	Unisolation of an Isolated Loop 3	7	12	30	Table V-2
13d	Unisolation of an Isolated Loop 4	5	10	30	Table V-2
13e	Unisolation of an Isolated Loop 5	6	11	30	Table V-2
14	Emergency Condenser Initiation into Idle Loop	21	24	30	Table V-2
15	Shutdown Cooling Initiation into Isolated Loop	30	34	240	Table V-2

Table 4.3.1-1
NMP1 – 80-Year Transient Occurrence Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Occurrences to-date (9/30/23)	80-Year Projected Transient Occurrences	Number of Design Transient Occurrences	UFSAR Sections and Tables
16	Inadvertent Start of Cold Loop	13	26	NA (Note 3)	Table V-2
16a	Inadvertent Start of Cold Loop 1	0	1	20	Table V-2
16b	Inadvertent Start of Cold Loop 2	4	7	20	Table V-2
16c	Inadvertent Start of Cold Loop 3	3	6	20	Table V-2
16d	Inadvertent Start of Cold Loop 4	3	6	20	Table V-2
16e	Inadvertent Start of Cold Loop 5	3	6	20	Table V-2
17	Emergency Condenser into Pumped Loop	19	27	500	Table V-2
18	Recirculation Pump Hot Loop Startup	276	397	NA (Note 3)	Table V-2
18a	Recirculation Pump Hot Loop 1 Startup	53	75	300	Table V-2
18b	Recirculation Pump Hot Loop 2 Startup	52	72	300	Table V-2
18c	Recirculation Pump Hot Loop 3 Startup	57	81	300	Table V-2
18d	Recirculation Pump Hot Loop 4 Startup	58	84	300	Table V-2
18e	Recirculation Pump Hot Loop 5 Startup	56	85	300	Table V-2
22	Turbine Trip	23	28	40	(Note 4)
23	Interruption/Loss of Feedwater Heaters	37	44	80	(Note 4)
24	Loss of Feedwater Flow	0	1	80	(Note 4)
25	Overpressure to 1,250 psig	0	1	1	(Note 4)
26	Overpressure to 1,375 psig	0	1	1	(Note 4)
27	Hydrostatic Pressure Test	1	1	3	(Note 4)
28	Operating Basis Earthquake (OBE)	0	1	NA	(Note 4)
29	SRV Actuations	419	492	500 (Note 3)	(Note 4)
29a	SRV Actuation, SRV1	68	80	NA (Note 5)	(Note 4)
29b	SRV Actuation, SRV2	80	94	NA (Note 5)	(Note 4)
29c	SRV Actuation, SRV3	68	80	NA (Note 5)	(Note 4)
29d	SRV Actuation, SRV4	68	80	NA (Note 5)	(Note 4)
29e	SRV Actuation, SRV5	70	83	NA (Note 5)	(Note 4)

Table 4.3.1-1
NMP1 – 80-Year Transient Occurrence Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Occurrences to-date (9/30/23)	80-Year Projected Transient Occurrences	Number of Design Transient Occurrences	UFSAR Sections and Tables
29f	SRV Actuation, SRV6	65	75	NA (Note 5)	(Note 4)
30	Emergency Condenser Actuation (Subsequent Actuation)	142	160	NA (Note 5)	(Note 4)
31	Emergency Condenser Actuation (Stop Actuation)	184	212	NA (Note 5)	(Note 4)
32	Loss of Reactor Water Cleanup (RWCU)	132	159	NA (Note 5)	(Note 4)
33	Loss of RWCU Extra Tin Peak-Valley	62	76	NA (Note 5)	(Note 4)

NOTES:

- Note 1:** Transient numbers 3 through 8, 10, 11, and 19 through 27 are based on the original GE thermal cycle diagrams for the reactor vessel. Transients 1, 2, 9, 12 through 18, and 28 through 33 were added since they are associated with transients that contribute to fatigue usage on other components or provide information to the Fatigue Monitoring (B.3.1.1) program. Although transients 19, 20, and 21 are defined on the GE thermal cycle diagrams, these transients do not contribute to fatigue and therefore, are not listed in this table.
- Note 2:** The number of 80-year projected transient occurrences in column four, for transients 5, 7, and 8 exceed the “original” number of design transient occurrences in column five of this table. However, the assumed number of design transient occurrences do not represent a final design limit; rather, the design limits are: a CUF value 1.0 or a CUF_{en} value of 1.0 for components which are evaluated for environmentally assisted fatigue. If monitored incremental CUF or CUF_{en} values determined periodically by SI:FatiguePro™ based on actual occurrences exceed 80 percent of the applicable design limit during the SPEO, then the condition will be entered into the corrective action program and evaluated for corrective action to be taken prior to exceeding the applicable final design limit acceptance criterion.
- Note 3:** Transients 13, 16, 18, and 29 are a sum of constituent events, which are SRV1 to SRV6 for SRV Actuators, and loop 1 to 5 events for the other grouped events. The number of design transient occurrences is not specified for transients 13, 16, and 18.
- Note 4:** The design transient occurrences are not specified in the UFSAR but are specified in other analyses or within the Fatigue Monitoring (B.3.1.1) program.
- Note 5:** Transients 28, 29a through 29f, 30 and 31 did not specify a number of a design transient occurrences in the design basis of NMP1 and were added into the Fatigue Monitoring (B.3.1.1) program based on cycle counting at other BWRs, or were analyzed in a separate CLB analysis. Transients 32 and 33 were created for the SPEO and do not have an associated number of a design transient occurrences.

Table 4.3.1-2 NMP1 – Limiting Locations and 80-Year Projected CUF and CUF_{en} Values						
No.	Location Description	Material (Note 5)	Thermal Zone	80-Year CUF_{en}	80-Year CUF	Acceptance Criterion
1	EC Nozzle Junction (EC_NOZJNC)	SS	EC Shell Side	0.027	(Note 2)	1.0
2	EC Tube-to-Tubesheet Weld (EC_TSHTWLD)	SS	EC Shell and Tube	0.037	(Note 2)	1.0
3	EC Tubing (EC_TUBE)	SS	EC Shell and Tube	0.033	(Note 2)	1.0
4	EC Tubesheet (EC_TUBESHT)	SS	EC Shell and Tube	0.030	(Note 2)	1.0
5	Feedwater Nozzle Blend Radius (FW_BR) (Note 3)	LAS	RPV Region A	0.592	(Note 2)	1.0
6	Feedwater Nozzle Safe End (FW_SE) (Note 3)	CS	FW System Near	0.231	(Note 2)	1.0
7	Core Spray Piping Point 1J (PIPE_CS) (Note 3)	SS	Core Spray Near	0.003	(Note 2)	1.0
8	Feedwater Piping Point 255, Welding Tee (PIPE_FW) (Note 3)	CS	FW System Far	0.061	(Note 2)	1.0
9	Feedwater/RWCU Mixing Region (PIPE_FWRWCU) (Note 4)	CS	FW/RWCU Mixing	0.842	(Note 2)	1.0
10	Recirculation Piping Point 3905, As-Welded Transition (PIPE_RECIRC) (Note 3)	SS	Recirc System	0.055	(Note 2)	1.0
11	RWCU Piping Point A20, Pipe-Valve Transition (PIPE_RWCU_A20) (Note 4)	SS	RWCU System	0.468	(Note 2)	1.0
12	RWCU Piping Point A80 (PIPE_RWCU_A80) (Note 4)	SS	RWCU System	0.422	(Note 2)	1.0
13	Basin Seal Skirt to Vessel Flange Junction (RPV_BASSKT)	CS/LAS	RPV Region A	(Note 1)	0.236	1.0
14	Closure Studs (Bolts) (RPV_BOLTS)	LAS	RPV Region A	(Note 1)	0.175	1.0
15	RPV Lower Head, Element D cut D Inside (RPV_BOTTHEAD) (Note 3)	LAS	RPV Region C	0.263	(Note 2)	1.0

Table 4.3.1-2 NMP1 – Limiting Locations and 80-Year Projected CUF and CUF _{en} Values						
No.	Location Description	Material (Note 5)	Thermal Zone	80-Year CUF _{en}	80-Year CUF	Acceptance Criterion
16	RPV CRD Return Nozzle (RPV_CRDRTN) (Note 4)	LAS	CRD Return Nozzle	0.751	(Note 2)	1.0
17	RPV CRD Stub Tube (RPV_CRDSTUB) (Note 4)	SS	RPV Region C	0.268	(Note 2)	1.0
18	Core Spray Nozzle Forging (302B Point 35) (RPV_CSNOZ) (Note 3)	LAS	Core Spray Near	0.002	(Note 2)	1.0
19	Core Spray Nozzle Safe End (304SS Point 20) (RPV_CSSE) (Note 3)	SS	Core Spray Near	0.002	(Note 2)	1.0
20	Recirculation Inlet Nozzle Safe End to Nozzle Weld (RPV_RECIN) (Note 3)	SS	Recirc System	0.041	(Note 2)	1.0
21	Recirculation Outlet Nozzle Blend Radius (RPV_RECOUT) (Note 3)	LAS	RPV Region B	0.045	(Note 2)	1.0
22	Torus Shell (TORUS_SHELL) (Note 4)	CS	(Note 6)	(Note 1)	0.057	1.0
23	Torus-Attached Piping XS-326 (TORUS_XS326)	CS	(Note 6)	(Note 1)	0.030	1.0
24	Torus-Attached Piping XS-337 (TORUS_XS337)	CS	(Note 6)	(Note 1)	0.090	1.0

NOTES:

- Note 1:** CUF_{en} is not applicable for this location because it is not exposed to the reactor coolant environment.
- Note 2:** The CUF value is not included in the table because it is bounded by the CUF_{en} value.
- Note 3:** NUREG/CR-6260 location for the older-vintage GEH plant.
- Note 4:** New monitored location.
- Note 5:** Materials listed are LAS – Low Alloy Steel, CS – Carbon Steel, and SS – Stainless Steel.
- Note 6:** This location does not have an applicable thermal zone and was not considered in EAF screening as this location is not exposed to the reactor coolant environment.

4.3.2 REACTOR VESSEL AND PIPING FATIGUE ANALYSES

TLAA Description:

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) reactor pressure vessel (RPV) was originally designed for 40 years of service in accordance with the ASME Boiler and Pressure Vessel Code, Section I, Power Boilers, 1962 Edition and Addenda plus the Nuclear Code Cases applicable on December 11, 1963. Fatigue usage factors were computed for reactor vessel critical locations using methods similar or identical to ASME Section III. Based on the number and type of design basis transients for the 40-year design life, cumulative usage factor (CUF) values were calculated for the critical locations of the RPV, where it was shown that all CUFs were less than 1.0.

Piping at NMP1 was originally designed in accordance with the ASA (ANSI) B31.1 Code, 1955 Edition, including applicable case interpretations for nuclear service, which did not include requirements for explicit fatigue analyses. For the purposes of fatigue monitoring only, fatigue calculations were performed for selected locations consistent with the guidance in ASME Section III. These selected locations were then added to SI:FatiguePro™ from which it is demonstrated the CUFs for each location would not exceed the ASME Section III design limit of 1.0 for all the postulated transients and transient occurrences. The remaining NMP1 piping components that were not implemented into the Fatigue Monitoring (B.3.1.1) program use implicit fatigue analyses, which also are TLAAs and are addressed in SLRA Section 4.3.4.

The original, 40-year fatigue analyses were evaluated for a 60-year service life and for environmentally assisted fatigue (EAF) as part of the NMP1 first license renewal application commitments.

The NMP1 first license renewal application committed to implementing the Fatigue Monitoring (B.3.1.1) program to include automated transient occurrence counting and automated calculation and tracking of fatigue CUFs. As a result, SI:FatiguePro™ software was implemented at NMP1 in 2007. SI:FatiguePro™ is a computerized data acquisition software that records thermal transients and calculates CUF and environmentally adjusted cumulative usage factor (CUF_{en}) values consistently with current licensing basis (CLB) fatigue analyses, after each new actual transient occurrence.

These 60-year evaluations now serve as the CLB and have been identified as TLAAs for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

All NMP1 reactor vessel components and associated piping component fatigue analyses are based on the transient occurrences listed in SLRA Table 4.3.1-1. Table 4.3.1-2 documents the 80-year CUF and CUF_{en} projections for plant-specific limiting locations. Table 4.3.1-2 demonstrates that the 80-year projected values of CUF and CUF_{en} for all locations remain less than the ASME Section III acceptance criteria through the end of the SPEO.

To ensure the projected CUF and CUF_{en} values in Table 4.3.1-2 remain acceptable for the 80-year period of operation, the Fatigue Monitoring (B.3.1.1) program will continue to monitor actual transient occurrences and the associated CUF and CUF_{en} values for

all limiting locations and ensure corrective actions are taken, if necessary, prior to exceeding the ASME Section III acceptance criterion.

The Fatigue Monitoring (B.3.1.1) program will continue to use SI:FatiguePro™ to compute actual CUF and CUF_{en} values for all monitored locations. With this approach, the original numbers of design transient occurrences are no longer a limit; instead, the ASME Section III acceptance criterion is the limit for each monitored location.

The Fatigue Monitoring (B.3.1.1) program includes requirements that initiate corrective actions if any accumulated CUF or CUF_{en} values exceed 80 percent of the ASME Section III acceptance criteria. Corrective actions may include revision of the affected analyses to address higher CUF or CUF_{en} values, establishing an inspection program using an approach acceptable to the NRC (such as inspections performed in accordance with Appendix L of ASME Code Section XI based on flaw tolerance analysis), or repair or replacement of affected components prior to the CUF or CUF_{en} values exceeding the acceptance criteria.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the Fatigue Monitoring (B.3.1.1) program through the subsequent period of extended operation. The Fatigue Monitoring (B.3.1.1) program will manage these TLAA(s) and associated effects of fatigue on the RPV and piping through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.3 FATIGUE OF THE EMERGENCY CONDENSERS

TLAA Description:

Section 4.3.7 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Nine Mile Point Nuclear Station, Unit 1 (NMP1) in which fatigue analyses were performed for the emergency condensers. The tube and shell sides of the emergency condensers were designed in accordance with ASME Section III, Class 2 and 3, respectively.

In 1997, failures of the original tubing were attributed to thermal fatigue resulting from leakage past the condensate return line. As a result of this failure, a subsequent modification and repair was performed which replaced the tube bundles for each of the emergency condensers. Fatigue loading was evaluated by calculating the alternating stresses associated with applicable design transients and determining a cumulative usage factor (CUF) based on the number of anticipated transients for the life of the condensers.

While the CUF values of the modified emergency condensers were all shown to be less than 1.0, certain locations required continued monitoring to demonstrate compliance over the licensed life of the plant. Therefore, these analyses have been identified as TLAA's that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The Fatigue Monitoring (B.3.1.1) program currently uses SI:FatiguePro™ to monitor fatigue of the bounding component locations, computing the CUF-to-date values based upon the cumulative numbers of fatigue transient cycles that have occurred as of the monitoring date.

The bounding NMP1 emergency condenser locations: EC Nozzle Junction (EC_NOZJNC), EC Tube-to-Tubesheet Weld (EC_TSHTWLD), EC Tubing (EC_TUBE), and EC Tubesheet (EC_TUBESHT) are currently monitored by the SI:FatiguePro™ software. SLRA Table 4.3.1-2 (component numbers 1, 2, 3 and 4) shows that the 80-year CUF and environmentally adjusted cumulative usage factor (CUF_{en}) projections for these component locations will not exceed the ASME Section III limit of 1.0 prior to the end of the SPEO.

The Fatigue Monitoring (B.3.1.1) program includes requirements that initiate corrective actions if any accumulated CUF or CUF_{en} values exceed 80 percent of the ASME Section III acceptance criteria. Corrective actions may include revision of the affected analyses to address higher CUF or CUF_{en} values, establishing an inspection program using an approach acceptable to the NRC (such as inspections performed in accordance with Appendix L of ASME Code Section XI based on flaw tolerance analysis), or repair or replacement of affected components prior to the CUF or CUF_{en} values exceeding the acceptance criteria.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the Fatigue Monitoring (B.3.1.1) program through the subsequent period of extended operation. The Fatigue Monitoring (B.3.1.1) program will manage the TLAA(s) and associated effects of fatigue on the emergency

condenser through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.4 ASME SECTION III, CLASS 2 AND 3, AND ANSI B31.1 ALLOWABLE STRESS ANALYSIS AND HELB EXCLUSIONS OF RECIRCULATION PIPING ANALYSIS

TLAA Description:

Nine Mile Point Nuclear Station, Unit 1 (NMP1) safety-related piping, and other piping that is in scope for subsequent license renewal was originally designed in accordance with the 1955 Edition of the ASA (ANSI) B31.1 Power Piping Code.

Piping systems designed in accordance with the ASME Section III Class 2 and 3, and B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but rather, cyclic loading is implicitly considered in a simplified manner in the design process. ASME Section III Class 2 and 3, and B31.1 design rules require a stress range reduction factor be used based on the number of thermal and pressure occurrences expected during the component operating lifetime. If the total number of fatigue occurrences is expected to be 7,000 or less, the stress range reduction factor of 1.0 is applied. For greater numbers of fatigue occurrences, a stress range reduction factor of less than 1.0 is applied, which reduces the allowable stress range. The stress range reduction factors for piping designed to ASME Section III Class 2 and 3, and B31.1 requirements are shown in Table 4.3.4-1.

Industry guidance shows that piping systems with operating temperatures less than 220 degrees F for carbon steel piping systems and 270 degrees F for austenitic stainless steel piping systems may be excluded from implicit fatigue concerns.

The evaluation for required stress range reduction factors performed as part of the piping design per ASME Section III, Class 2 and 3, and B31.1 are implicit fatigue analyses since they are based upon the number of thermal occurrences anticipated for the life of the piping system; therefore, they are TLAAs requiring evaluation for the subsequent period of extended operation (SPEO).

Table 4.3.4-1 Stress Range Reduction Factors	
Number of Equivalent Full Temperature Occurrences	Stress Range Reduction Factor
7,000 and less	1.0
7,000 to 14,000	0.9
14,000 to 22,000	0.8
22,000 to 45,000	0.7
45,000 to 100,000	0.6
100,000 and over	0.5

In addition, the NMP1 UFSAR (Reference 4.8.1) Section XVI, Subsection D.2.0 documents that the original design basis for NMP1 is that the probability of double-ended guillotine pipe rupture is extremely low such that protection from the dynamic

effects of that rupture were not considered. NMP1 UFSAR Sections XVI, Subsection 2.1 and Subsection 2.2 document how the effects of pipe whip from high energy breaks inside containment and outside containment were evaluated. These sections describe that the 12 high energy systems inside containment, listed in NMP1 UFSAR Table XVI-28, and the 12 high energy systems outside containment, listed in NMP1 UFSAR Table XVI-29 were evaluated. It was assumed that any one of these lines could break anywhere inside the primary containment or at any point outside of the primary containment respectively. Therefore, no locations inside or outside of containment on piping segments for these systems were excluded from high energy line break (HELB) analysis.

Typically, locations are excluded from HELB consideration are based on time-limited evaluations (e.g., the locations CUF values will remain below 0.1 over 40 years). As explained above these evaluations are not found in the NMP1 current licensing basis. However, a portion of the reactor recirculation system was evaluated in response to NRC Information Notice 89-55 (Reference 4.8.25). The evaluation excluded some recirculation system piping segments from further consideration using the guidance in Branch Technical Position MEB 3-1 (Reference 4.8.26) Section B.1.C(2) which allows the exclusions of high energy pipe segments with calculated stresses less than $0.8(1.8S_h + S_A)$. Since the allowable stress (S_h) and stress range (S_A) are a function of the stress range reduction factor for cyclic conditions, further evaluation would be necessary if the actual number of full range temperature occurrences exceeded a value of 7,000. If non-class 1 high energy piping locations in the reactor recirculation system that were originally not selected for HELB analyses exceed 7,000 thermal occurrences, then the stress range reduction factor would have to be applied (e.g. less than 1.0) and the HELB selection methodology may require the addition of new locations for HELB analyses.

TAA Evaluation:

SLRA Tables 3.x.2-y (see SLRA Section 3.0) identify piping located within piping systems that were designed in accordance with ASME Section III, Class 2 and 3, or B31.1 requirements and are associated with implicit fatigue analyses. Portions of the following license renewal piping systems were designed in accordance with ASME Section III, Class 2 and Class 3, or B31.1 requirements and are only affected by the same pressure and temperature transients as the reactor coolant system transients that are listed in SLRA Table 4.3.1-1: Condenser Air Removal and Off-Gas System, Control Rod Drive System, Core Spray System, Feedwater/High Pressure Coolant Injection System, Liquid Poison System, Main Steam System, Main Turbine and Auxiliaries System, Radioactive Waste System (Feedwater Vent Piping and Recirculation Pump Seal Leak Detection Drain Lines), Reactor Pressure Vessel Instrumentation System, Reactor Recirculation System, Sampling System (Reactor Recirculation Sampling Line and Feedwater-HPCI Sample Lines), and Shutdown Cooling System.

Only a subset of the transients listed in SLRA Table 4.3.1-1 apply to the above Class 2 and Class 3, and B31.1 piping within each system. The summation of all 80-year transient occurrence projections from SLRA Table 4.3.1-1 is less than 4,000 occurrences. Therefore, even if all operational reactor coolant system transients were applied to each of these systems, the total number of projected 80-year occurrences is significantly less than 7,000. Therefore, the stress range reduction factors originally

applied for the piping sub-systems within these piping systems remain applicable and these implicit TLAAAs remain valid through the SPEO. As such, the original selection scope for the HELB analysis of the Reactor Recirculation System remains valid for the SPEO.

Some systems or portions of the following license renewal piping systems were designed in accordance with ASME Section III, Class 2 and Class 3, or B31.1 requirements and are affected by thermal and pressure transients that are different than the reactor coolant system transients listed in SLRA Table 4.3.1-1: Electric Steam Boiler System, Emergency Cooling System, Emergency Diesel Generator System (Engine Exhaust Piping), Fire Detection and Protection System (Diesel Fire Pump Engine Exhaust Piping), Reactor Water Cleanup System, and Sampling System (Main Steam Sample Lines and RWCU Regen HX Outlet Sample Lines).

SLRA Table 4.3.4-2 documents these systems or sub-systems and provides descriptions of the transient occurrences that result in thermal or pressure occurrences for these piping systems. The table also documents conservative 80-year projections of transient occurrences through the SPEO. The 80-year projected transient occurrences stated in SLRA Table 4.3.4-2 were developed using information from various sources including: system operational procedures, surveillance frequency schedules, estimates based on system maintenance, UFSAR operational requirements for the system, and additional projections defined in SLRA Table 4.3.1-1. In all cases, the conservative 80-year projected number of occurrences in SLRA Table 4.3.4-2 is significantly less than 7,000. Therefore, the stress range reduction factors originally applied for the piping sub-systems within these piping systems remain applicable and these implicit TLAAAs remain valid through the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – All ASME Section III, Class 2 and 3, and B31.1 allowable stress analyses and associated HELB selection analysis of the Recirculation System remain valid through the subsequent period of extended operation and the reduction of stress range reduction factors are not required.

Table 4.3.4-2

**80-Year Transient Occurrence Projections for Class 2, Class 3, and ANSI B31.1 Piping Systems
Affected by Transients Other Than RCS Transients**

Piping System	Description of Transient Occurrences that Affects the Piping System	Conservative Assumptions Used in 80-Year Projections	Total Projected Occurrences for 80 Years
Electric Steam Boiler	Plant Heatup	218	1,474
	Plant Cooldown	216	
	Boiler Inspection – Yearly	80	
	Boiler Operation – Monthly	960	
Emergency Cooling	RCS Transients	4,000	4,026
	Pre-startup Testing	10	
	Heat Removal Capacity Test	16	
Emergency Diesel Generator – Engine Exhaust Piping	Operability Test – Monthly	960	1,410
	Test For Automatic Startup and Pickup of Load Required For A Loss-Of-Coolant Accident – every 2 years	40	
	Startup to Support Various Engine Maintenance Activities	250	
	Load Rejection Test – 2 years	40	
	Performance Run – 4 years	20	
	Pre-Operational Testing	100	
Diesel Fire Pump Engine – Exhaust Piping	Fire Pump Start	2,520	2,941
	Diesel Fire Pump Performance Test – Yearly	80	
	Diesel Engine Start During and Post Maintenance	81	
	Fire Protection System Actuation - 2 Startups/Shutdown per year	160	

Table 4.3.4-2

**80-Year Transient Occurrence Projections for Class 2, Class 3, and ANSI B31.1 Piping Systems
Affected by Transients Other Than RCS Transients**

Piping System	Description of Transient Occurrences that Affects the Piping System	Conservative Assumptions Used in 80-Year Projections	Total Projected Occurrences for 80 Years
	Pre-Operational Testing of Diesel Fire Pump	100	
Reactor Water Cleanup	RCS Transients	4,000	4,170
	RWCU Pump Maintenance – Yearly	80	
	RWCU Preoperational Testing	10	
	RWCU Heat Exchanger Maintenance – Yearly	80	
Main Steam Sample Lines	RCS Transients	4,000	5,120
	Manual Sampling During Plant Operation – Monthly	960	
	Transients Resulting from System Maintenance – 2 per year	160	
RWCU Regen HX Outlet Sample Lines	RCS Transients	4,000	5,290
	Manual Sampling During Plant Operation – Monthly	960	
	Transients Resulting from System Maintenance – 2 per year	160	
	RWCU Pump Maintenance – Yearly	80	
	RWCU Preoperational Testing	10	
	RWCU Heat Exchanger Maintenance – Yearly	80	

4.3.5 ENVIRONMENTALLY ASSISTED FATIGUE ANALYSIS

TLAA Description:

NUREG-2191, Revision 1, (Reference 4.8.4) Section X.M1, “Fatigue Monitoring,” provides guidance for evaluating the effects of reactor water environment on the fatigue life of ASME Section III components that contact the reactor coolant. One acceptable method for satisfying this guidance is to assess the impact of the reactor coolant environment on a sample set of critical components. These critical components should include those listed in NUREG/CR-6260 (Reference 4.8.20) for the plant type and vintage. Additional component locations should also be considered if they are more limiting than those listed in NUREG/CR-6260 for the plant.

In 2007, the Nine Mile Point Nuclear Station, Unit 1 (NMP1) SI:FatiguePro™ software was modified to include the calculation and tracking of environmentally assisted fatigue (EAF) cumulative usage factors (CUF_{en}) at the locations identified in NUREG/CR-6260 for the older-vintage GEH plant. For these locations, the CUF_{en} values were calculated using the appropriate environmental fatigue correction factor (F_{en}) relationships from NUREG/CR-6583 (Reference 4.8.27) (for carbon and low alloy steels), NUREG/CR-5704 (Reference 4.8.28) (for stainless steels), and NUREG/CR-6909, Revision 0 (Reference 4.8.29) as appropriate for each location, and are tracked by the Fatigue Monitoring (B.3.1.1) program.

TLAA Evaluation:

For the NMP1 Subsequent License Renewal Project, environmental fatigue screening calculations were performed for all RPV, piping, and other component locations that have an identified CUF value in an NMP1 current licensing basis (CLB) evaluation and are in contact with reactor water. In addition, environmental fatigue calculations were prepared in accordance with NUREG/CR-6909, Revision 1 (Reference 4.8.30), for component locations listed in NUREG/CR-6260 for the older-vintage BWR, which correlates to NMP1, and additional locations that may be more limiting.

Environmental Fatigue Screening

The environmental fatigue screening calculation methodology is described below.

- 1) All component locations that have documented cumulative usage factors in the NMP1 CLB were identified.
- 2) Locations were excluded if not in contact with reactor water.
- 3) Bounding F_{en} values based on material type, maximum temperature, and chemistry were calculated; and bounding 80-year CUF_{en} values were estimated for all locations.
 - a) For each component location, 80-year CUF values were estimated, for screening purposes only, based on linear extrapolation of the corresponding published 40-year or 60-year CUF values.
- 4) Locations with bounding CUF_{en} values less than 1.0 were excluded, except for locations that were analyzed in NUREG/CR-6260 or are currently monitored.

- 5) Locations that undergo essentially the same thermal and pressure transients during plant operations were grouped together into “thermal zones”.
 - a) The thermal zones and materials of fabrication associated with the limiting EAF locations are given in SLRA Table 4.3.1-2.
- 6) Within each material type in a thermal zone, the location with the greatest estimated 80-year CUF_{en} value was selected (“Screened In”). The location with the second highest 80-year CUF_{en} value was also selected (“Screened In”) if within 25 percent of the highest CUF_{en} and the bounding 80-year CUF_{en} value was greater than or equal to 1.0.
- 7) Remaining locations were excluded except for locations that were analyzed in NUREG/CR-6260 or are currently monitored.
- 8) It was verified that component locations that were “Screened Out” were originally evaluated to the same technical rigor as those component locations which were “Screened In” such that the “Screened In” locations bound the “Screened Out” locations. Each “Screened In” location bounds (for fatigue) “Screened Out” locations with the same material within the associated thermal zone. All “Screened Out” components within a thermal zone are represented by a least one “Screened In” component of the same material type.
 - a) No thermal zones were screened out and no thermal zones bound or represent another thermal zone. As a result, each “Screened In” location bounds (for fatigue) “Screened Out” locations with the same material within the associated thermal zone. All “Screened Out” components within a thermal zone are represented by a least one “Screened In” component of the same material type.

This methodology “Screened In” 19 locations, in which SI:FatiguePro™ will monitor for EAF during the subsequent period of extended operation (SPEO). Five are new locations, 10 are locations identified in NUREG/CR-6260, and four are additional locations that were previously monitored by SI:FatiguePro™ and are in contact with reactor coolant.

In the NMP1 EAF screening calculations, for each “wetted” location, a bounding 80-year F_{en} was determined using the methodology from NUREG/CR-6909, Revision 1, Appendix A as appropriate for the material for each location. Bounding F_{en} values are based on material type, maximum temperature, maximum sulfur content (for carbon steel and low alloy steel materials), minimum strain rate, and dissolved oxygen values that yielded the largest F_{en} values. For materials for which a varying dissolved oxygen parameter from NUREG/CR-6909, Revision 1, Appendix A is used, the F_{en} value is calculated as a weighted average based on time spent in each dissolved oxygen regime.

Environmental Fatigue Analyses

Detailed EAF evaluations were performed on all “Screened In” component locations as follows.

Eighty-year fatigue usage values were calculated using ASME Code methodology (N-415.2 or NB-3222.4(e)) except that the applicable fatigue curves from NUREG/CR-6909, Revision 1 were used in addition to the applicable ASME Code fatigue curves. Projected 80-year usage values adjusted for environmental fatigue (CUF_{en}) were calculated by multiplying the projected 80-year usage values (CUF) by the environmental fatigue correction factors (F_{en}). The 80-year projected transient occurrences shown in SLRA Table 4.3.1-1 were used as inputs in the environmental fatigue analyses. An average temperature value approach was used in the detailed EAF analysis.

All projected 80-year usage values (CUF) and projected 80-year usage values adjusted for environmental fatigue (CUF_{en}) are documented in SLRA Table 4.3.1-2.

The environmental fatigue analyses will be managed by the Fatigue Monitoring (B.3.1.1) program using the SI:FatiguePro™ software, including periodic validation of cycles and water chemistry parameters that contribute to F_{en} . The Fatigue Monitoring (B.3.1.1) program includes requirements that initiate corrective actions if any accumulated CUF or CUF_{en} values exceed 80 percent of the ASME Section III acceptance criteria. Corrective actions may include revision of the affected analyses to address higher CUF or CUF_{en} values, establishing an inspection program using an approach acceptable to the NRC (such as inspections performed in accordance with Appendix L of ASME Code Section XI based on flaw tolerance analysis), or repair or replacement of affected components prior to the CUF or CUF_{en} values exceeding the acceptance criteria.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the Fatigue Monitoring (B.3.1.1) program through the subsequent period of extended operation. The Fatigue Monitoring (B.3.1.1) program will manage the TLAA(s) and associated effects of environmentally assisted fatigue on the RPV and piping components through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.6 REACTOR VESSEL INTERNALS FATIGUE ANALYSES

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) reactor vessel internals were not designed in accordance with ASME Section III. Therefore, determination of cumulative usage factors (CUFs) was not required. However, a CUF value was identified for the steam dryer support brackets over the original 40-year reactor pressure vessel life, as discussed in SLRA Section 4.3.6.4. In addition, fatigue analyses were performed for the core shroud repair hardware. Note, SLRA Section 4.3.6.1 discusses the original conical support and tie-rod fatigue analysis, a separate tie-rod fatigue analysis was performed for a subsequent modification which addressed other sub-components of the tie-rods, as discussed in SLRA Section 4.3.6.3.

4.3.6.1 CORE SHROUD SUPPORT STABILIZER TIE ROD AND CONICAL SUPPORT FATIGUE ANALYSIS

TLAA Description:

Section 4.3.5 of Nine Mile Point Nuclear Station's First License Renewal Application (FLRA) documented a TLAA for Unit 1 (NMP1) in which a fatigue analysis of the core shroud stabilizer assemblies (tie-rods) was performed using ASME Section III methodology.

A core shroud repair was installed in 1995 to structurally replace the core shroud's horizontal welds H1 through H7. The design consists of four shroud stabilizer tie-rod assemblies combined with core plate wedges, which were installed approximately 90 degrees apart in the core shroud/reactor pressure vessel annulus, between attachment points at the top of the upper core shroud head flange and the core shroud conical support.

General Electric (GE) documented the fatigue analysis and cumulative usage factor (CUF) value of the shroud conical support (tie-rod attachment points) using transients and transient occurrences assumed to occur over the life of the repair. The maximum CUF for any part of the conical support and tie-rods or their attachment points was 0.0081 for the life of the repair.

Since this fatigue analysis assumed a number of transient occurrences over the life of the shroud stabilizer tie-rod repair, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

This fatigue analysis of the conical support and tie-rods has been reevaluated for the SPEO using the 80-year projected transient occurrences in SLRA Table 4.3.1-1. The resultant CUF is 0.0085, which is significantly less than the ASME Code Section III design limit of 1.0.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The core shroud support stabilizer tie-rod and conical support fatigue analysis has been successfully projected through the subsequent period of extended operation.

4.3.6.2 CORE SHROUD VERTICAL WELD REPAIR CLAMPS FATIGUE ANALYSIS

TLAA Description:

Section 4.3.5 of Nine Mile Point Nuclear Station's First License Renewal Application (FLRA) documented a TLAA for Unit 1 (NMP1) in which a fatigue analysis of the core shroud vertical weld repair clamps was performed using ASME Section III, Subsection NG, 1989 Edition methodology.

A core shroud vertical weld repair was installed in 1999 to structurally replace the core shroud's vertical welds V9 and V10. The design consists of two clamps that are used for the V9 weld and two clamps for the V10 weld which bridge across the flawed welds and transmit the pressure load.

The design analysis of the vertical weld repair clamps documented a cumulative usage factor (CUF) value using transient and transient occurrences over the life of the repair. The maximum CUF value was 0.0236 for the life of the repair.

Since this fatigue analysis assumed a number of transient occurrences over the life of the vertical weld repair clamps, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The fatigue analysis of the vertical weld repair clamps has been reevaluated for the SPEO using the 80-year projected transient occurrences in SLRA Table 4.3.1-1. The resultant bounding CUF is 0.0284, which is significantly less than the ASME Code Section III design limit of 1.0.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The vertical weld repair clamp fatigue analysis has been successfully projected through the subsequent period of extended operation.

4.3.6.3 CORE SHROUD STABILIZER MODIFIED UPPER SUPPORTS FATIGUE ANALYSES

TLAA Description:

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) shroud stabilizer assembly upper supports were replaced in 2007 after a potential for high peak stresses in the original shroud stabilizer upper support design was discovered. The replacement hardware was analyzed for fatigue in accordance with the ASME Section III, Subsection NG, 2001 Edition and including the 2003 Addenda.

General Electric (GE) documented the fatigue analysis and cumulative usage factor (CUF) values of the shroud stabilizer modified upper support components in a proprietary report using transients and transient occurrences assumed to occur over a 40-year component life.

Since this fatigue analysis assumed a number of transient occurrences over the life of the modified upper supports, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The projected number of transient occurrences through the SPEO assumed in the fatigue analysis of the modified upper support components are all less than the assumed occurrences in the corresponding fatigue analysis documented in the proprietary GE report. Therefore, the calculated CUF values for these components will not exceed the ASME Section III limit during the SPEO. The assumed transient occurrences for the original design life of the modified upper supports are valid through the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The core shroud stabilizer modified upper support fatigue analysis remains valid through the subsequent period of extended operation.

4.3.6.4 STEAM DRYER SUPPORT BRACKET FATIGUE ANALYSIS

TLAA Description:

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) steam dryer support brackets were analyzed for cyclic loading at the “U-plate to bracket weld” location for 40 years of operation. The analysis of the steam dryer support brackets documented a cumulative usage factor (CUF) value of 0.268, based on an assumed 402 cycles and an allowable number of 1,500 cycles. The assumed 402 cycles were specified as the number of temperature changes in the dryer region of the reactor pressure vessel, corresponding to 120 startup/shutdown cycles, 200 scram cycles, 80 loss of feedwater flow cycles, one overpressure 1250 psig cycle, and one overpressure to 1375 psig cycle.

Since this fatigue analysis assumed a number of transient occurrences over the life of the steam dryer support brackets, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The fatigue analysis of the steam dryer support brackets has been reevaluated for the SPEO using a total of 500 transient occurrences. The 500 transient occurrences are based on the 80-year projected occurrences documented in SLRA Table 4.3.1-1 for startup/shutdown (transient number 4), scram (transient number 11), loss of feedwater flow (transient number 24), overpressure to 1,250 psig (transient number 25), overpressure to 1,375 psig (transient number 26), and an additional 97 thermal cycles to account for margin. The resultant 80-year CUF is 0.333, which is less than the defined acceptance criteria of 0.8.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The steam dryer support bracket fatigue analysis has been successfully projected through the subsequent period of extended operation.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

4.4.1 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

TLAA Description:

Thermal, radiation, and cyclical aging analyses of plant electrical components, developed to meet 10 CFR 50.49 requirements, have been identified as TLAAAs for Nine Mile Point Nuclear Station, Unit 1 (NMP1). The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function 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, or post-LOCA environment. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

Environmental Qualification Program Background

The Environmental Qualification of Electric Equipment (B.3.1.3) program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics, and the environmental conditions to which the components could be subjected. The environmental qualification methodology for equipment installed prior to February 22, 1983, is in accordance with the Division of Operating Reactors (DOR) Guidelines or IEEE Standard 323-1974, as implemented by NRC Regulatory Guide (RG) 1.89, Revision 1. The environmental qualification methodology for equipment installed after February 22, 1983, is in accordance with IEEE Standard 323-1974, as implemented by NRC RG 1.89, Revision 1 unless there are sound reasons to the contrary.

Aging evaluations for electrical components in the Environmental Qualification of Electric Equipment (B.3.1.3) program that specify a qualification of at least 60 years are TLAAAs for subsequent license renewal because the criteria contained in 10 CFR 54.3 are met.

TLAA Evaluation:

Under 10 CFR 54.21(c)(1)(iii), the Environmental Qualification of Electric Equipment (B.3.1.3) program, which implements the requirements of 10 CFR 50.49 (as further defined and clarified by the NRC Division of Operating Reactors, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" which was an enclosure to NRC IE Bulletin 79-01B, dated January 14, 1980, is an aging management program for license renewal.

Reanalysis of an aging evaluation to extend the qualifications of components is performed as part of the Environmental Qualification of Electric Equipment (B.3.1.1) program. The program complies with all applicable regulations and manages

equipment thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. 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). Environmentally qualified equipment must be refurbished, replaced, or have its qualification extended prior to reaching the aging limits established in the aging evaluation.

TLAA demonstration to option 10 CFR 54.21(c)(1)(iii) is chosen, which states that the effects of aging will be adequately managed for the subsequent period of extended operation, and the Environmental Qualification of Electric Equipment (B.3.1.3) program will manage the aging effects of the components associated with the environmental qualification TLAA.

NUREG-2191, Revision 1 (Reference 4.8.4) states that the NRC evaluated the EQ program based on 10 CFR 50.49 and determined that it is an acceptable aging management program to address environmental qualification according to 10 CFR 54.21(c)(1)(iii).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be adequately managed through the subsequent period of extended operation by the Environmental Qualification of Electric Equipment (B.3.1.3) program.

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS

4.5.1 CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS

The Nine Mile Point Nuclear Station, Unit 1 containment does not have pre-stressed tendons. As such, this topic is not a TLAA.

4.6 **PRIMARY CONTAINMENT FATIGUE ANALYSES**

Subsequent to the original design, the Nine Mile Point Nuclear Station, Unit 1 (NMP1) primary containment was reanalyzed in response to the discovery of additional hydrodynamic loads not considered in the original design of the Mark I containment. As a result, General Electric initiated the Mark I Containment Program. The detailed guidance of the long-term program is contained in the NRC Safety Evaluation Report, NUREG-0661 (Reference 4.8.32), and its supplements which describe the generic hydrodynamic load definition and structural acceptance criteria consistent with the requirements of the applicable codes and standards. The NMP1 primary containment was reanalyzed to evaluate the effects of the “new” hydrodynamic loads resulting from a blowdown into the suppression chamber during a postulated loss of coolant accident (LOCA) or an electromatic relief valve (ERV) discharge. Components of the primary containment that were reanalyzed included the torus shell, external support system, vent header system and internal structures, and piping attached to the torus, (including shell penetrations, internal piping, and supports); and were summarized in the Plant Unique Analysis Report (PUAR) Volumes I and II. As such, since these components were analyzed for fatigue, these analyses are considered TLAAAs.

Note that the suppression chamber assembly is often referred to as the “torus” and the ERV’s and main steam safety relief lines are often referred to as safety relief valves (SRVs) and SRV lines respectively in some parts of the NMP1 UFSAR (Reference 4.8.1) and the NMP1 PUAR and are used interchangeably in the discussions that follow.

The main steam piping drywell penetrations and the six ERV expansion joint bellows were previously replaced and designed to accommodate movements and cyclic requirements. As such, the main steam piping penetration bellows and ERV expansion joint bellows are considered TLAAAs.

The spent fuel pool (SFP) underwent a planned modification to increase the storage capacity of the pool. Part of this work involved analyzing the SFP liner and new SFP storage racks for fatigue and are therefore the analyses are considered TLAAAs.

The following primary containment structures, piping, penetrations, and associated components have been analyzed for fatigue or cyclic requirements and have been identified as TLAAAs that require evaluation for the subsequent period of extended operation:

- Torus Shell Fatigue Analysis (Section 4.6.1)
- Vent System Fatigue Analysis (Section 4.6.2)
- Torus Attached Piping Analysis (Section 4.6.3)
- Fatigue of Primary Containment Penetrations (Section 4.6.4)
- SRV Piping Supports Fatigue Analyses (Section 4.6.5)
- Main Steam Piping Penetration Bellows Cycle Limits (Section 4.6.6)
- ERV Bellows Cycle Limits (Section 4.6.7)

- Spent Fuel Pool Liner Fatigue Analysis (Section 4.6.8)
- Spent Fuel Pool Storage Rack Fatigue Analysis (Section 4.6.9)

4.6.1 TORUS SHELL FATIGUE ANALYSIS

TLAA Description:

Section 4.6.1 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which new hydrodynamic loads were identified subsequent to the original design of the Mark I containment system. These additional loads result from blowdown into the suppression chamber (torus) during a postulated loss of coolant accident (LOCA) and loads that could occur during normal operation, such as safety relief valve (SRV) discharges. The results of the analyses of these effects were presented in the Plant Unique Analysis Report (PUAR).

The NMP1 PUAR describes the fatigue analysis of the torus shell and external support system and presented the cumulative usage factors (CUFs) associated with loads resulting from normal operation and accident conditions for the peak stress locations of the torus shell for 40 years. The fatigue analysis of the torus shell was performed in accordance with ASME Section III, Division 1, with addenda through summer 1977, and Code Case N-197. Normal operating conditions assumed 500 SRV actuations.

The reported 40-year CUF values for the bounding peak stress location (Element 165) in the torus shell is 0.018 for normal operation, 0.002 for an intermediate/small break accident (IBA/SBA) event, and 0.034 for a design basis accident (DBA) event.

Since the fatigue analysis of the torus shell resulted in calculated CUF values using transients and transient occurrences assumed to occur over the life of the plant, the PUAR has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

Since NMP1 has not experienced an IBA/SBA, or a DBA, the only non-accident condition transient contributing to fatigue usage is periodic SRV actuations for the life of the plant during normal operation.

The Fatigue Monitoring (B.3.1.1) program currently uses SI:FatiguePro™ to monitor fatigue of the bounding component locations, computing the CUF-to-date values based upon the cumulative number of fatigue transient occurrences that have occurred as of the monitoring date.

The Fatigue Monitoring (B.3.1.1) program monitors the fatigue usage of the bounding torus shell and external support system location using SI:FatiguePro™ software. SLRA Table 4.3.1-1 (component number 22) shows that the 80-year CUF projection for this component location will not exceed the ASME Section III limit of 1.0 prior to the end of the SPEO.

The Fatigue Monitoring (B.3.1.1) program includes requirements that initiate corrective actions if any CUF values exceed 80 percent of the ASME Section III acceptance criteria. Corrective actions may include revision of the affected analyses to address higher CUF values, establishing an inspection program using an approach acceptable to the NRC (such as inspections performed in accordance with Appendix L of ASME Code Section XI based on flaw tolerance analysis), or repair or replacement of affected components prior to the CUF values exceeding the acceptance criteria.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the Fatigue Monitoring (B.3.1.1) program through the subsequent period of extended operation. The Fatigue Monitoring (B.3.1.1) program will manage the TLAA(s) and associated effects of fatigue on the torus shell through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.6.2 VENT SYSTEM FATIGUE ANALYSIS

TLAA Description:

Section 4.6.1 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which new hydrodynamic loads were identified subsequent to the original design of the Mark I containment system. The results of the analyses of these effects were presented in the Plant Unique Analysis Report (PUAR).

The NMP1 PUAR described the fatigue analysis of the vent system. The fatigue analysis of the vent system evaluated fatigue on eight separate locations of the vent system, in which it was assumed that all maximum stresses occur simultaneously, and that all cycles reach these maximum values. The cumulative usage factors (CUFs) for all of the vent system locations were calculated considering the stresses associated with loadings due to chugging, which is an accident condition loading. The PUAR documents a duration of 900 seconds of chugging during accident conditions as the bounding load for fatigue. Normal and upset transients were not considered in this calculation.

A re-evaluation of the original vent system fatigue analysis was issued to account for the effect of increased stresses resulting from water which had accumulated in the vent header spherical intersections. Therefore, fatigue of the vent system components was re-evaluated to account for a higher frequency of the chugging load. The maximum CUF determined in the disposition was 0.86 for the vent header/vent pipe spherical intersection location, based on the stresses developed during a postulated accident.

Since the vent system fatigue analyses resulted in calculated CUF values using transient occurrences assumed to occur over the life of the plant, these analyses have been identified as TLAA's that must be re-evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The fatigue analyses of the vent system components only considered the stresses from chugging developed during a postulated accident (intermediate/small break accident), the effects of normal operation transients, such as safety relief valve actuations, have an insignificant impact on the fatigue of the vent system. Since the postulated accident is considered a one-time event, which has not occurred at NMP1, the transient occurrences and loadings that were assumed in the fatigue analysis of the vent system are still valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The vent system fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.6.3 TORUS ATTACHED PIPING ANALYSIS

TLAA Description:

Section 4.6.2 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which to fulfill the objectives of the Mark I Containment Long Term Program, modifications to the configuration of the torus attached piping (TAP) and safety relief valve (SRV) piping were performed. The NMP1 TAP and SRV Piping were evaluated by a generic fatigue analysis for Class 2 and 3 piping which was submitted for NRC approval by the Mark I Containment owners' group (Reference 4.8.33). This evaluation defined the bounding conditions and determined that the stress levels and cycles involved would not produce a fatigue problem, with cumulative usage factors (CUFs) of less than 0.5 at the end of 40 years of operation. This analysis indicated that the stress results for the most limiting piping systems and locations were selected for each plant, such that the remainder of the TAP and SRV lines at NMP1 should have lower fatigue usage, which was accepted by the NRC. The generic analysis assumed 500 SRV actuations, five operating basis earthquakes (OBE), and one accident condition consisting either of a design basis accident (DBA) or intermediate break accident/small break accident (IBA/SBA) for a 40-year plant lifetime.

The Plant Unique Analysis Report (PUAR) described these fatigue evaluations and stated that the conclusions of the generic analysis were applicable to the NMP1 TAP and SRV piping, concluding that no further analysis was necessary.

Two NMP1 specific locations were analyzed in the generic analysis, consisting of TAP locations torus-attached piping XS-326 and torus-attached piping XS-337. The maximum CUF for the two analyzed NMP1 locations was 0.036 for 40-years, based on normal operating conditions (NOC) and accident conditions. This maximum CUF location is associated with torus-attached piping XS-337, which is the 12-inch core spray suction line for pump #111 that enters the torus at penetration XS-337.

Since the PUAR reported the generic analysis which resulted in calculated CUF values using transients and transient occurrences assumed to occur over the life of the plant, these analyses have been identified as TLAA's that must be re-evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The fatigue evaluation of the TAP and SRV Piping considered periodic SRV actuations during normal operating conditions for the life of the plant, OBE, and accident condition transients. NMP1 has not experienced a DBA, IBA/SBA, OBE, or safe shutdown earthquake. Therefore, the only non-accident or earthquake contributors to the TAP and SRV piping fatigue usage is SRV actuations during normal operating conditions.

The Fatigue Monitoring (B.3.1.1) program currently uses SI:FatiguePro™ to monitor fatigue of the bounding component locations, computing the CUF-to-date values based upon the cumulative numbers of fatigue transient occurrences that have occurred as of the monitoring date.

The bounding NMP1 specific locations discussed in the generic analysis, torus-attached piping XS-326 (TORUS_XS326) and torus-attached piping XS-337 (TORUS_XS337) are currently monitored by the SI:FatiguePro™ software. SLRA

Table 4.3.1-1 (component numbers 23 and component 24) show that the 80-year CUF projections for these component locations will not exceed the ASME Section III limit of 1.0 prior to the end of the SPEO.

The Fatigue Monitoring (B.3.1.1) program includes requirements that initiate corrective actions if any CUF values exceed 80 percent of the ASME Section III acceptance criteria. Corrective actions may include revision of the affected analyses to address higher CUF values, establishing an inspection program using an approach acceptable to the NRC (such as inspections performed in accordance with Appendix L of ASME Code Section XI based on flaw tolerance analysis), or repair or replacement of affected components prior to the CUF values exceeding the acceptance criteria.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the Fatigue Monitoring (B.3.1.1) program through the subsequent period of extended operation. The Fatigue Monitoring (B.3.1.1) program will manage the TLAA(s) and associated effects of fatigue on the TAP and SRV piping through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.6.4 FATIGUE OF PRIMARY CONTAINMENT PENETRATIONS

4.6.4.1 SRV PENETRATION FATIGUE ANALYSIS

TLAA Description:

Section 4.6.5 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which a fatigue analysis of the safety relief valve (SRV) penetrations (where the SRV line penetrates the vent header spherical intersection) was performed in accordance with ASME Section III, 1977 Edition through the summer 1977 Addenda.

The Plant Unique Analysis Report (PUAR) stated that the fatigue evaluation of the SRV penetration locations showed that the maximum load could be cycled on the penetrations for at least 7,500 cycles without exceeding code allowable values. The PUAR stated the major load component in this case is SRV actuations during accident conditions (SRV case C3.3), which can only occur for up to 50 stress cycles, and the number of these events considered in the design basis is only one. The reported number of 7,500 allowable stress cycles was based on a calculated stress intensity of 41,360 psi associated with a postulated intermediate break/small break accident (IBA/SBA).

These statements in the PUAR originate from the SRV penetration component specific stress and fatigue analysis. The SRV penetration fatigue analysis stated the stress intensity of 41,360 psi, reported in the PUAR, and calculated a corresponding alternating stress value of 20,680 psi, which resulted in 60,000 allowable stress cycles, stating that the penetration will respond to the cyclic loading for the life of the plant. Neither the SRV penetration component specific fatigue analysis nor the PUAR presented a cumulative usage factor. The SRV penetration component specific analysis stated that changes in SRV loads do not greatly affect the total stress intensity at the penetration, and therefore it is appropriate to conclude that 60,000 allowable stress cycles based on IBA/SBA loadings is the bounding value for the SRV penetrations.

Since this analysis considered a number of cycles related to anticipated transient occurrences assumed to occur over the life of the plant, this analysis has been identified as TLAA's that must be re-evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The fatigue analysis of the SRV penetrations determined the number of allowable stress cycles based on a postulated IBA/SBA load combination, which considers accident and earthquake loadings. Since the postulated accident is considered a one-time event, which has not occurred at NMP1, the transient occurrences and loadings that were assumed in the fatigue analysis of SRV penetrations are still valid for 80 years.

Even though SRV actuations during normal operating conditions (NOC) were not included in the determination of the number of allowable stress cycles for the SRV penetrations, for conservatism the loadings associated with NOC (SRV actuations) were considered using the 80-year SRV actuation projection in SLRA Table 4.3.1-1, (transient number 29b) and combined with the loadings associated with an IBA/SBA

using the guidance contained in the generic Mark I containment report (Reference 4.8.33). These combined loadings (NOC + IBA/SBA) result in 20,950 effective stress cycles that would apply to SRV penetrations at 80-years. There remains adequate margin in the 80-year stress cycles when compared to the number of allowable cycles for the SRV penetration (60,000). Therefore, the fatigue analysis of the SRV penetrations remains valid for the subsequent period of extended operation.

TAA Disposition: 10 CFR 54.21(c)(1)(i) – The SRV penetration fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.6.4.2 TAP PENETRATIONS FATIGUE ANALYSES

TLAA Description:

Section 4.6.5 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which fatigue analyses of the torus attached piping (TAP) penetrations were performed in accordance with ASME Section III, 1977 Edition through the summer 1977 Addenda.

Specific stress and fatigue analyses were performed for the TAP penetrations where each analysis considered the loadings associated with a postulated loss of coolant accident. For each of the TAP penetration specific analyses the maximum number of assumed stress cycles for all loading events was estimated to be 10,000, where the stresses associated with a design basis accident (DBA) load combination were conservatively applied for each fatigue cycle. Each of the small bore and a portion of the large bore TAP penetration analyses determined the number of allowable cycles based on the stresses generated during a DBA. A portion of the large bore TAP penetrations determined the number of allowable cycles based on the stresses generated during an intermediate/small break accident (IBA/SBA). The cumulative usage factors (CUFs) for each TAP penetration were calculated at the fillet weld of the penetration's nozzle-shell intersection or the reinforcement pad edge.

The maximum CUF calculated from the TAP penetration specific analyses that determined the number of allowable cycles based on a DBA case was 0.962 for the small bore torus drain line TAP penetration locations (XS-362, XS-363), based on an assumed 10,000 stress cycles and a allowable of 10,400 cycles. The 10,400 allowable stress cycles were determined using the stresses occurring during a DBA.

The maximum CUF calculated from the TAP penetration specific analyses that determined the number of allowable cycles based on an IBA/SBA case was 0.38 for the large bore containment spray suction pump TAP penetration locations (XS-342, XS-324, XS-341, XS-325), based on an assumed 10,000 stress cycles and an allowable of 26,000 cycles. The 26,000 allowable stress cycles were determined using the stresses occurring during a IBA/SBA.

The PUAR summarized the TAP penetration specific analyses, stating that the maximum load could be cycled on each penetration for at least 10,000 cycles without exceeding code allowables.

Since the TAP penetration fatigue analyses considered a number of cycles related to anticipated transient occurrences assumed to occur over the life of the plant, these analyses have been identified as a TLAA's that must be re-evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The fatigue analyses of the TAP penetrations did not consider safety relief valve (SRV) actuations during normal operating conditions (NOC), and the allowable and assumed stress cycles were based on postulated accident and earthquake loadings. Since the postulated accidents are considered one-time events, which have not occurred at NMP1, the transient occurrences and loadings that were assumed in the fatigue analyses of the TAP penetrations are still valid for 80 years.

Even though SRV actuations during NOC were not included in the fatigue analyses of the TAP penetrations, for conservatism the loadings associated with NOC (SRV actuations) were considered using the 80-year SRV actuation projection in SLRA Table 4.3.1-1, (transient number 29) and combined with the loadings associated with either a DBA or IBA/SBA using the guidance contained in the generic Mark I containment report (Reference 4.8.33). The combined loadings of (NOC + DBA) result in 5,761 effective stress cycles that would apply to the small bore and a portion of the large bore TAP penetrations at 80-years. The combined loadings of (NOC + IBA/SBA) result in 24,930 effective stress cycles that would apply to a portion of the large bore TAP penetrations at 80-years. There remains adequate margin in the 80-year stress cycles when compared to the number of allowable cycles for the bounding TAP penetration that determined the number of allowable cycles based on a DBA case (10,400) and for the bounding TAP penetration that determined the number of allowable cycles based on a IBA/SBA case (26,000). Therefore, the fatigue analyses of the TAP penetrations remain valid for the subsequent period of extended operation and the 10 CFR 54.21(c)(1) disposition of these TLAA's is in accordance with 10 CFR 54.21(c)(1)(i).

For two TAP penetrations, XS-333 and XS-337, a conservative discrepancy was identified in the number of allowable cycles for these two analyses. This condition was entered into the corrective action program for resolution, and the number of allowable cycles for penetrations XS-333 and XS-337 were revised to 76,528 and 157,081 respectively. The number of allowable cycles for XS-333 were determined using the stresses occurring during a DBA. The number of allowable cycles for XS-337 were determined using the stresses occurring during an IBA/SBA. The combined loadings of (NOC + DBA) and (NOC + IBA/SBA) results in 5,761 and 24,930 effective stress cycles, respectively, that would apply to these two TAP penetrations at 80-years. There remains adequate margin in the 80-year stress cycles when compared to the number of allowable cycle for TAP penetrations XS-333 (76,528) and XS-337 (157,081). Therefore, these two TAP penetration fatigue analyses (XS-333, XS-337) have been successfully projected through the subsequent period of extended operation and the 10 CFR 54.21(c)(1) disposition of these two TLAA's is in accordance with 10 CFR 54.21(c)(1)(ii).

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The TAP penetrations fatigue analyses (except for XS-333 and XS-337) have been demonstrated to remain valid through the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – Two of the TAP penetrations (XS-333 and XS-337) fatigue analyses have been projected through the subsequent period of extended operation.

4.6.5 SRV PIPING SUPPORTS FATIGUE ANALYSES

TLAA Description:

The Plant Unique Analysis Report (PUAR) reported a number of modifications that were performed for the safety relief valve (SRV) piping supports. Fatigue analyses were performed for a subset of the SRV piping supports that attach to the main vent piping and the vent sphere – vent header intersections. These analyses were performed in accordance with ASME Section III, 1977 Edition through the summer 1977 Addenda.

The SRV support fatigue analyses each considered the same loadings associated with a postulated loss of coolant accident. For each of the SRV support fatigue analyses the maximum number of assumed stress cycles for all loading events was estimated to be 10,000, where the maximum stress was conservatively applied for each fatigue cycle, and the number of allowable cycles were calculated based on the stresses generated during a design basis accident (DBA). The cumulative usage factors (CUFs) for each support were calculated at the fillet weld of the reinforcement pad edge that attaches to the vent sphere or main vent piping. The maximum CUF calculated for the SRV supports was 0.91, for the lower-rigid support in the main vent piping, based on an assumed 10,000 stress cycles and an allowable of 11,000 cycles. The 11,000 allowable cycles were determined using the maximum vent stresses occurring during a DBA event.

Since the SRV supports fatigue analyses considered a number of cycles related to anticipated transient occurrences assumed to occur over the life of the plant, these analyses have been identified as TLAA's that must be evaluated for the subsequent period of extended operation.

TLAA Evaluation:

The fatigue analyses of the SRV supports did not consider SRV actuations during normal operating conditions (NOC), and the allowable and assumed stress cycles were based on postulated accident and earthquake loadings. Since the postulated accidents are considered one-time events, which have not occurred at NMP1, the transient occurrences and loadings that were assumed in the fatigue analyses of the SRV supports are still valid for 80 years.

Even though SRV actuations during NOC were not included in the fatigue analyses of the SRV supports, for conservatism the loadings associated with NOC (SRV actuations) were considered using the 80-year SRV actuation projection in SLRA Table 4.3.1-1, (transient number 29b) and combined with the loadings associated with a DBA using the guidance contained in the generic Mark I containment report (Reference 4.8.33). These combined loadings (NOC + DBA) result in 2,179 effective stress cycles that would apply to SRV supports at 80-years. There remains adequate margin in the 80-year stress cycles when compared to the number of allowable cycles for the bounding SRV support (11,000). Therefore, the fatigue analyses of the SRV supports remain valid for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The SRV supports fatigue analyses have been demonstrated to remain valid through the subsequent period of extended operation.

4.6.6 MAIN STEAM PIPING PENETRATION BELLOWS CYCLE LIMITS

TLAA Description:

The main steam piping drywell penetrations (PENET-X-2A/B) were modified between 1990 and 1991, by adding "clam-shell" expansion joint bellows to accommodate thermal expansion as well as any movement due to a line rupture. The internal and external bellows were designed for 65,000 and 52,000 design cycles respectively, and 200 incident cycles each. The design cycles are associated with accommodating the maximum movements of any one or a combination of normal conditions of power output (startup and shutdown transients) or an incident condition when a failure occurs (design basis accident (DBA)). Therefore, since the main steam piping penetration internal and external expansion joint bellows were designed with cyclical limits associated with anticipated transient occurrences assumed to occur over the life of the plant, it has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

Since the DBA is considered a one-time event, which has not occurred at NMP1, the assumed 200 cycles associated with the movements of a DBA are bounding during the SPEO. SLRA Table 4.3.1-1 documents that 218 startup (transient number 4) and 216 shutdown (transient number 6) transient occurrences are projected for 80 years. These projections are both significantly less than the 65,000 cycles specified for the internal bellows and 52,000 cycles specified for the external bellows. Therefore, the transient conditions and associated cycles that were assumed for the design life of the main steam piping penetration bellows are valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The main steam piping penetration bellows cycle limits have been demonstrated to remain valid through the subsequent period of extended operation.

4.6.7 ERV BELLOWS CYCLE LIMITS

TLAA Description:

There are six expansion joint bellows (EXJBJ-66-01R through EXJBJ-66-06R) that connect the electromatic relief valve (ERV) enclosure discharge to the discharge piping that goes to the Y-quenchers in the torus. The expansion joint bellows were replaced in 1990, after inspections revealed signs of cracking and corrosion. The replacement expansion joints were analyzed in accordance with the standards of the Expansion Joint Manufacturers Association, Inc. as modified to the requirements of ASME Section III Subsection NC 3649, for movements and cyclic requirements based on a specified 40-year life. The replacement ERV expansion joint bellows were designed for at least 16,000 primary design condition cycles. The design condition is associated with the ERV bellows permitting movement of the main steam piping during warm-up (startup and shutdown transients).

Therefore, since the ERV expansion joint bellows were designed with cyclical limits associated with anticipated transient occurrences assumed to occur over the life of the plant, it has been identified as a TLAA that must be evaluated for the subsequent period of extended operation.

TLAA Evaluation:

SLRA Table 4.3.1-1 documents that 218 startup (transient number 4) and 216 shutdown (transient number 6) transient occurrences are projected for 80 years. These projections are both significantly less than the 16,000 cycles specified for the design cycle life of the ERV bellows. Therefore, the transient conditions and associated cycles that were assumed for the design life of the ERV bellows are valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The ERV bellows cycle limits have been demonstrated to remain valid through the subsequent period of extended operation.

4.6.8 SPENT FUEL POOL LINER FATIGUE ANALYSIS

TLAA Description:

The spent fuel pool (SFP) storage capacity was expanded in 1999, and new fuel storage racks were installed. Although not required by ASME Section III, the portion of the SFP liner which supports the new fuel storage racks was evaluated for fatigue using the guidance of ASME Section III.

The fatigue evaluation assumed one safe shutdown earthquake (SSE) and five operating basis earthquake (OBE) transients. The resulting fatigue evaluation calculated a cumulative usage factor (CUF) value of 0.0092.

Since the analysis resulted in a calculated CUF value using transients and transient occurrences assumed to occur over the life of the plant, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

SLRA Table 4.3.1-1 documents that one OBE (transient number 28) is projected for 80 years. Nine Mile Point Nuclear Station, Unit 1 has not experienced an SSE or OBE, and the assumed one SSE and five OBE transients are bounding during the SPEO. Therefore, the transients and transient occurrences that were assumed in the original analysis are still valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The spent fuel pool line fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.6.9 SPENT FUEL POOL STORAGE RACK FATIGUE ANALYSIS

TLAA Description:

The spent fuel pool (SFP) storage capacity was expanded in 1999, and new fuel storage racks were installed. Although not required by ASME Section III, the new fuel storage racks were evaluated for fatigue using the guidance of ASME Section III.

The fatigue evaluation assumed one safe shutdown earthquake (SSE) and five operating basis earthquake (OBE) transients. The resulting fatigue evaluation calculated a cumulative usage factor (CUF) value of 0.564.

Since the analysis resulted in a calculated CUF value using transients and transient occurrences assumed to occur over the life of the plant, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

SLRA Table 4.3.1-1 documents that one OBE (transient number 28) is projected for 80 years. Nine Mile Point Nuclear Station, Unit 1 has not experienced an SSE or OBE, and the assumed one SSE and five OBE transients are bounding during the SPEO. Therefore, the transients and transient occurrences that were assumed in the original analysis are still valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The spent fuel pool storage rack fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

This section evaluates:

- Reactor Vessel and Reactor Vessel Head Flaw Evaluations (Section 4.7.1)
- Reactor Water Cleanup System Weld Overlay Fatigue Flaw Growth Evaluations (Section 4.7.2)
- Generic Letter 81-11, “Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking”” (Section 4.7.3)
- Valve Fatigue Analyses (Section 4.7.4)
- ERV Vacuum Breaker Valve Fatigue Analysis (Section 4.7.5)
- Core Spray System Weld Fatigue Flaw Growth Analysis (Section 4.7.6)
- CRD Bottom Head Penetrations Fracture Mechanics Analysis (Section 4.7.7)
- Crane Cyclic Loading Analyses (Section 4.7.8)
- Core Shroud Tie Rod X-750 Inconel Component Service Life (Section 4.7.9)

4.7.1 REACTOR VESSEL AND REACTOR VESSEL HEAD FLAW EVALUATIONS

4.7.1.1 REACTOR VESSEL FLAW EVALUATIONS

TLAA Description:

Section 4.7.4 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which unacceptable indications in the reactor pressure vessel (RPV) shell were identified in 1999 by ultrasonic testing (UT) in axial weld RVWD-140 and shell-to-flange circumferential weld RVWD-099. A total of nine indications were found that did not meet the acceptance standards of ASME Section XI, Subsection IWB-3500. Two of the indications were located in axial weld RVWD-140 and seven indications were located in shell-to-flange circumferential weld RVWD-099. The detected flaws were subsurface planar flaws located parallel to the centerline of the weld (i.e., the indications in RVWD-140 were axially-oriented and the indications in RVWD-099 were circumferentially-oriented).

A structural evaluation of the flaws was performed by comparing the flaw characteristics to pre-determined flaw acceptability criteria in accordance with ASME Section XI, Subsection IWB-3600. The flaw evaluations considered fatigue crack growth and irradiation embrittlement (only applicable for weld RVWD-140) to 28 effective full power years (EFPY).

To meet first license renewal commitments, the flaw evaluations were revised for the subject flaws to consider additional fatigue crack growth and the effects of additional irradiation embrittlement using the projected fluence values for 46 EFPY (to the end of the first period of extended operation). The revised evaluations used the number of 463 transient cycles corresponding to the difference between 46 EFPY and the actual EFPY at the time of flaw detection. The NRC SER (Reference 4.8.37) concluded that the updated analysis adequately demonstrated that NMP1 could be operated without repair of the RPV welds until the end of the first period of extended operation.

Since the flaw evaluations of the RPV welds included an assumption of fluence and a total amount of fatigue crack growth based on the current operating term, these analyses have been identified as TLAA's that must be re-evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

A flaw analysis of the RPV shell flaws was performed for all nine indications considering fatigue crack growth and irradiation embrittlement through the end of the SPEO. The analysis was performed utilizing the previous methodology and flaw handbook.

The projected 67 EFPY fluence values were used to determine the effects of embrittlement for RVWD-140, demonstrating that the fracture toughness of the indications remain bounded by the previous evaluation. The evaluation analytically grew the indications considering 882 cycles of operation utilizing the prior methodology. The evaluation concluded that the indications with flaw growth meet the acceptance criteria of the established flaw handbook, and are therefore acceptable for continued operation through the end of the SPEO.

In addition, volumetric examinations of the RPV welds, performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, provide additional confirmation that the flaws remain within the bounding flaw dimensions. Inspection for RVWD-140 and RVWD-099 in the third and fourth inservice inspection (ISI) intervals have been performed and determined that the previously detected indications have not significantly changed. Both RVWD-140 and RVWD-099 are within the scope of the ISI program for the fifth ISI interval, as documented in the fifth interval ISI program plan.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program through the subsequent period of extended operation. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will manage the TLAA(s) and associated effects of cracking on the reactor pressure vessel welds through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.7.1.2 REACTOR VESSEL CLOSURE HEAD FLAW EVALUATIONS

TLAA Description:

Section 4.7.4 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which an unacceptable subsurface flaw indication in the reactor pressure vessel (RPV) closure head was identified in 2003 by ultrasonic testing (UT) in closure head meridional weld RVWD-005. The flaw was determined to be unacceptable per ASME Section XI, Subsection IWB-3500; therefore, a flaw evaluation in accordance with the methodology of ASME Section XI, Subsection IWB-3600 was performed. The crack growth analysis considered 240 startup and shutdown cycles. The analysis determined the flaw was acceptable for continued service until the end of the first period of extended operation, as accepted by the NRC.

In addition, an unacceptable indication between the RPV head flange and closure head was identified in 2011 by UT in circumferential weld RVWD-001. The flaw was determined to be unacceptable per ASME Section XI, IWB-3500; therefore, a flaw evaluation in accordance with the methods of ASME Section XI IWB-3610 was performed. The evaluation considered 463 transient cycles corresponding to 46 effective full power years (EFPY) of operation. The evaluation also determined that fluence was negligible at the RPV closure head, such that fracture toughness of RVWD-001 would remain unchanged through the first period of extended operation. The NRC SER of this evaluation (Reference 4.8.38) concluded that the closure head weld joining the RPV closure flange forging to the head was acceptable for continued operation.

Since the flaw evaluations of the RPV closure head welds included assumptions of a total amount of fatigue crack growth based on the current operating term, these analyses have been identified as TLAAs that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

A flaw analysis was performed for the RPV closure head flaws considering fatigue crack growth through the end of the SPEO. The analysis was performed utilizing the previous methodology and flaw handbook. The projected 67 EFPY fluence values were used to confirm that at the axial height of the RPV closure head welds, the 80-year projected fluence values are below the threshold for fracture toughness property changes and are therefore not applicable to the RPV closure head indications.

The evaluation analytically grew the indication of RVWD-001 considering 841 operational cycles utilizing the prior methodology. As the indication of RVWD-005 was identified in 2003, and the flaw handbook utilized is valid for 40 additional years of operation from the finding, an additional 36 operational cycles were applied for the six additional years of operation to extend the results of the flaw handbook through the SPEO.

The evaluation concluded that the final crack size for RVWD-001 at the end of the SPEO is 1.59 inches which is less than the allowable flaw depth of 1.99 inches and that the final crack depth for RVWD-005 at the end of the SPEO is 0.315 inches which

is less than the allowable flaw depth of 0.328 inches. Therefore, the RPV closure head flaws remain acceptable for continued operation through the end of the SPEO.

In addition, examinations of the RPV closure head welds, performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, provide additional confirmation that the flaws remain within the bounding flaw dimensions. Re-examination for the subsurface flaw in RVWD-001 was not required in the fourth inservice inspection (ISI) interval. Successive re-examinations of RVWD-005 were performed in the third and fourth ISI intervals and concluded that there had been no changes in the previous recorded size. Both RVWD-005 and RVWD-001 are within the scope of the ISI program for the fifth ISI interval, as documented in the fifth interval ISI program plan.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program through the subsequent period of extended operation. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will manage the TLAA(s) and associated effects of cracking on the reactor pressure vessel closure head welds through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.7.2 REACTOR WATER CLEANUP SYSTEM WELD OVERLAY FATIGUE FLAW GROWTH EVALUATIONS

TLAA Description:

Section 4.7.5 of Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for Unit 1 (NMP1) in which fatigue crack growth analyses had been performed for two weld overlays (weld 33-FW-22 and weld 33-FW-23A) in the reactor water cleanup (RWCU) system. Weld 33-FW-22 was repaired in 1997 due to a through-wall pin hole leak by performing a weld overlay and is classified as an intergranular stress corrosion cracking (IGSCC) category E1 weld. Weld 33-FW-23A was repaired in 2004 due to a through-wall leak by performing a weld overlay and is classified as a IGSCC Category E1 weld.

The weld overlays consist of IGSCC resistant austenitic stainless steel material and, thus, are not susceptible to continued IGSCC crack propagation. However, the first 1/16-inch thick layer of weld metal deposited is not assumed to be IGSCC-resistant due to weld dilution; thus, it is assumed to be cracked. Fatigue crack growth analyses were performed for both weld overlays in accordance with ASME Section XI, Appendix C, with the crack propagating into the overlay from the hypothetical 1/16-inch deep crack.

The analysis for weld 33-FW-22 was performed in 1997 and assumed 154 startup/shutdown cycles. The final flaw depth to thickness ratio remained acceptable at 0.22 versus an allowable of 0.29. The analysis for weld 33-FW-23A was performed in 2005 and assumed 168 startup/shutdown cycles. The final flaw depth to thickness ratio was 0.172 compared to an allowable of 0.42, thus, the welds were acceptable for the cycles analyzed.

Since these analyses assumed cracking in a portion of the weld overlay and use transient and transient occurrences assumed to occur over the life of the plant, these evaluations are considered TLAAs that must be considered for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

SLRA Table 4.3.1-1 documents that 218 occurrences of startup (transient number 4) and 216 occurrences of shutdown (transient number 6) are projected at the end of the SPEO. As of December 31, 1995, NMP1 experienced 106 startup and 105 shutdown transients. As of May 13, 2005, NMP1 experienced 144 startup and 142 shutdown transients. Therefore, 33-FW-22 is projected to experience 112 startup/shutdown transient occurrences at the end of the SPEO, and 33-FW-23A is projected to experience 74 startup/shutdown transient occurrences at the end of the SPEO. These values are both below the postulated 154 and 168 startup/shutdown transients assumed in the original fatigue crack growth analyses for 33-FW-22 and 33-FW-23A, respectively.

However, to ensure continued acceptability, the welds are subject to augmented inspection under the BWR Stress Corrosion Cracking (B.2.1.5) program. The extent and schedule of the inspections is in accordance with the guidance defined in BWRVIP-75-A. Both welds have been inspected in each inservice inspection interval since their respective repairs, and the most recent inspections for both welds were

performed during the NMP1 spring 2023 refueling outage, finding no recordable indications in the weld overlay material.

The BWR Stress Corrosion Cracking (B.2.1.5) program will continue to perform inspections of the welds periodically, in accordance with the requirements of BWRVIP-75-A, to ensure no fatigue flaw growth has occurred into the weld overlays.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be managed by the BWR Stress Corrosion Cracking (B.2.1.5) program through the subsequent period of extended operation. The BWR Stress Corrosion Cracking (B.2.1.5) program will manage the TLAA(s) and associated effects of IGSCC on the reactor water cleanup system weld overlays through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.7.3 **GENERIC LETTER 81-11, “CRACK GROWTH ANALYSIS TO DEMONSTRATE CONFORMANCE TO THE INTENT OF NUREG-0619, “BWR FEEDWATER NOZZLE AND CONTROL ROD DRIVE RETURN LINE NOZZLE CRACKING””**

TLAA Description:

NUREG-0619 (Reference 4.8.40) was issued by the NRC per Generic Letter (GL) 81-11 in February 1981 (Reference 4.8.41) because of observed cracking on the inside surfaces of BWR feedwater (FW) and control rod drive return line (CRDRL) nozzles at the blend radius and bore. The causes included: 1) on-off feedwater flow control at low power, 2) high clad thermal stresses, and 3) leakage between the nozzle and the thermal sleeve. In the original BWR designs the thermal sleeve was loosely fit into the feedwater nozzle bore. The leakage caused rapid thermal cycling, that propagated due to larger (in terms of the magnitude of temperature and pressure change) thermal cycles resulting from plant transients. Such cracking was observed in the FW nozzles at Nine Mile Point Nuclear Station, Unit 1 (NMP1) prior to 1980.

NUREG-0619 provided recommendations for plant modifications to reduce or eliminate the rapid thermal cycling fatigue mechanism and provided inspection recommendations that were intended to detect cracking prior to becoming a safety issue.

Starting in 1977, the following NUREG-0619 recommended modifications were implemented at NMP1 to reduce or eliminate the FW nozzle rapid thermal cycling fatigue cracking mechanism: (a) removal of cladding from the nozzle bore and blend radii, (b) improved thermal sleeve and sparger design, (c) reactor water cleanup return line rerouted to the feedwater line, and (d) improved feedwater flow control. The CRDRL nozzle was modified by replacing the safe end with improved intergranular stress corrosion cracking resistant material and thermal sleeve so that examinations could be performed during the NMP1 1977 outage. The NMP1 welded-in-place CRDRL nozzle thermal sleeve design makes the nozzle less susceptible to rapid thermal fatigue cracking than the original designs implemented at other BWRs.

In addition to the recommended modifications, NUREG-0619 also established inspection intervals and methods. The growth of an assumed existing fatigue crack was used to define enhanced inspection intervals. A series of calculations including stress, fatigue usage, and crack growth of an assumed flaw were performed to determine conservative inspection intervals for the FW nozzles. These calculations were submitted to the NRC in 1984.

In 1994, NMP1 amended previous commitments with respect to the recommendations of NUREG-0619 in which it was proposed to perform ultrasonic testing (UT) techniques instead of dye penetrant testing (PT) examination. The submittal stated in the event no relevant indications are discovered, the examination frequency would revert to a frequency of once per 10-years in accordance with ASME Section XI. This request was supported by updated fatigue and fracture mechanics analyses which would be used to disposition indications if identified during UT inspection.

The results of the 1994 NMP1 FW nozzle analyses showed that an initial 0.25-inch depth flaw grew to a depth of 0.38-inches in the nozzle inner blend radius, and 0.33-inches in the nozzle bore region after 40 years of expected plant operating cycles using the ASME Code, Section XI crack growth relationships. The ASME Section XI

allowable flaw sizes are 0.95-inches for the inner blend radius region, and 0.71-inches for the nozzle bore region. The result of the 1994 NMP1 CRDRL nozzle analyses showed that an initial 0.25-inch depth flaw grew to a depth of 0.40-inches in the limiting nozzle location (blend radius region near the transition to the bore) after 40 years of expected plant operating cycles using the ASME Code, Section XI crack growth relationships. The ASME Section XI allowable flaw size for the analyzed section of the CRDRL nozzle is 0.5-inches.

In 1998, NMP1 revised its commitment for FW nozzle inspections to be in accordance with the recommendations in the BWROG Report, which provided technical justification for alternate BWR FW nozzle inspection requirements based on fracture mechanics evaluations performed to date, actual inspection experience, and advances in UT techniques since 1980. These BWROG evaluations relied on fracture mechanics analyses that modeled the flaws from a small crack, detectable by UT, to large detectable cracks which were still significantly less than the size for which a failure may be expected. The FW nozzle stress, fatigue, and crack growth analyses were revised to meet these requirements but did not change the results of the analyses.

The BWROG Report does not address CRDRL nozzle inspections and therefore NMP1 reaffirmed its commitment to perform periodic inspections of the NMP1 CRDRL nozzle in accordance with NUREG-0619, as amended by previous UT inspection commitments. These evaluations and proposed alternatives were accepted by the NRC in February 1999 as an acceptable alternative to the inspection guidelines in NUREG-0619.

The NMP First License Renewal Application (FLRA) credited enhanced inspections in accordance with the Inservice Inspection (ISI) program for the management of rapid thermal cycling fatigue cracking in the FW and CRDRL nozzles. The inspections would, in effect, provide confirmation that cracking due to rapid thermal cycling fatigue or low cycle fatigue is not occurring. In addition, the NMP1 FLRA credited the Fatigue Monitoring (B.3.1.1) program for aging management of low cycle fatigue in the FW nozzles.

Because of the cyclical nature of the assumptions of the postulated crack growth analyses, these analyses involve a time-limited period over the original design life of the plant, in which postulated cracks in the FW and CRDRL nozzles would not exceed the allowable values in Section XI of the ASME Code during the remainder of NMP1 operating life and are thus defined as a TLAA's which must be evaluated for 80 years.

TLAA Evaluation:

Periodic examinations of the FW and CRDRL nozzles, performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, provide confirmation that the cracking due to rapid thermal cycling fatigue and low cycle fatigue is not occurring. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program is credited for managing rapid thermal cycling fatigue through the subsequent period of extended operation (SPEO).

Examinations performed under the ISI program for the FW nozzles and the CRDRL nozzle in the fourth and fifth ISI intervals have discovered no reportable indications.

SLRA Section 4.3.2 describes how the Fatigue Monitoring (B.3.1.1) program is credited with managing fatigue of the reactor vessel. This includes fatigue associated with the FW nozzles and the CRDRL nozzle. The Fatigue Monitoring (B.3.1.1) program currently uses SI:FatiguePro™ to monitor low cycle fatigue of FW nozzles and the CRDRL nozzle, computing the cumulative usage factor (CUF)-to-date values based upon the cumulative numbers of fatigue transients that have occurred as of the monitoring date. The FW and CRDRL nozzles have also been evaluated for environmentally assisted fatigue (EAF) as described in SLRA Section 4.3.5.

The SI:FatiguePro™ locations “Feedwater Nozzle Blend Radius,” “Feedwater Nozzle Safe End,” and “RPV CRD return nozzle” will monitor fatigue for the FW and CRDRL nozzles to ensure that the CUF and CUF_{en} values will remain less than the acceptance criteria through the SPEO. These component locations are shown on SLRA Table 4.3.1-2 as component numbers 5, 6 and 16.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program is credited to continue to provide confirmation that cracking due to rapid thermal cycling fatigue has been mitigated in the FW and CRDRL nozzles. In addition, the Fatigue Monitoring (B.3.1.1) program is credited with managing the FW and CRDRL nozzles low cycle fatigue TLAAAs through the subsequent period of extended operation.

4.7.4 VALVE FATIGUE ANALYSES

4.7.4.1 FEEDWATER ISOLATION CHECK VALVES FATIGUE ANALYSIS

TLAA Description:

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) feedwater isolation check valves (CKV-31-01R and CKV-31-02R) were replaced in 2005 and designed in accordance with ASME Section III, Division 1, Subsection NC, 1986 Edition. These check valves are ASME Class 2 components, and while a fatigue analysis is not required, a fatigue evaluation was provided for the replaced feedwater check valves using the guidance of the ASME code.

The fatigue evaluation in the analysis assumed a total of 760 operating cycles consisting of 240 cycles of heatup, 229 cycles of cooldown, 10 cycles of emergency cooldown, 1 cycle of blowdown, and 280 scram cycles. In addition, five operating basis earthquake (OBE) and one safe shutdown earthquake (SSE) events, each comprised of 10 cycles were assumed, resulting in a total of 60 cycles. Therefore, the analysis considered a total of 820 cycles over a 40-year life. The resulting fatigue evaluation calculated a cumulative usage factor (CUF) of 0.68.

Since the fatigue analysis of the feedwater isolation check valves resulted in a calculated CUF value using transients and transient occurrences assumed to occur over the life of the plant, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

SLRA Table 4.3.1-1 documents 80-year transient projections for heatup (transient number 4), cooldown (transient number 6), emergency cooldown (transient number 9), single relief valve (SRV) blowdown (transient number 10), scram (transient number 11), and operating basis earthquake (OBE) (transient number 28). SLRA Table 4.3.1-1 demonstrates that the projected occurrences at 80 years all less than the assumed occurrences for these transients, and as the feedwater isolation check valves were replaced in 2005, the projected number of transients at the end of the SPEO is much lower. Nine Mile Point Nuclear Station, Unit 1 has not experienced an SSE transient, and the assumed SSE transient is bounding during the SPEO.

Therefore, the transients and transient occurrences that were assumed in the original analysis remain valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The feedwater isolation check valves fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7.4.2 EMERGENCY CONDENSER ISOLATION VALVES FATIGUE ANALYSIS

TLAA Description

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) emergency condenser isolation valves (ECIV's) (IV-39-07R through IV-39-10R) were replaced in 1983 and designed in accordance with ASME Section III, Summer 1980 Edition with Addenda up to and including summer 1982. These ECIV's are not ASME Class 1 components, and while a fatigue analysis is not required, a fatigue evaluation was provided for the replaced ECIV's using the guidance of the ASME code.

The design analysis evaluated fatigue in accordance with ASME Section III, Subsection NB-3500, "Valve Design," and demonstrated compliance with the acceptance criteria for normal duty valve fatigue requirements in accordance with NB-3545.3, by determining an allowable number of $1.0E+6$ cycles, against an applied 2,000 cycles of startup and shutdown transients. In addition, the design analysis demonstrated fatigue acceptance in accordance with ASME Section III, Subsection NB-3553, based upon an applied 10 cycles of "Quick Stop" corresponding to an instantaneous 475 degrees F heatup and 475 degrees F cooldown.

Since the ECIV design analysis demonstrated fatigue acceptance of the valves using transients and transient occurrences assumed to occur over the life of the plant, this analysis has been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The analysis considered an applied 2,000 cycles of normal duty operational cycles (100 degree F/hour change rate) corresponding to startup and shutdown transients. ECIV's IV-39-07R through IV-39-10R are normally on standby, with the isolation valves on the steam supply lines open, and would be expected to experience thermal cycles along with the reactor (startup and shutdown transients). In addition, it is also assumed that the ECIV's will experience normal duty operation cycles associated with the emergency condenser system specific transients.

SLRA Table 4.3.1-1 documents 80-year transient projections for normal startup (transient number 4), normal shutdown (transient number 6), emergency condenser actuation (stop actuation) (transient number 31), emergency condenser actuation (subsequent actuation) (transient number 30), emergency condenser initiation into idle loop (transient number 14), emergency condenser initiation into isolated loop (transient number 12), and emergency condenser into pumped loop (transient number 17). SLRA Table 4.3.1-1 demonstrates that the projected 80-year occurrences for these transients summed together is 860, which is less than the postulated 2,000 occurrences defined by ASME Section III, NB-3545.3.

In addition, to demonstrate acceptance in accordance with the requirements of ASME Section III, NB-3553, an applied 10 cycles of "Quick Stop" corresponding to an instantaneous 475 degrees F heatup and 475 degrees F cooldown were applied to the ECIVs. Experiencing 10 cycles of this transient is not credible, as the transient is defined to occur instantaneously. The only way a step-change in ECIV fluid temperature of 475 degrees F is possible would be during a loss-of-coolant accident

(LOCA). Nine Mile Point Nuclear Station, Unit 1 has not experienced a LOCA, therefore exceeding 10 cycles of this transient during the SPEO is not credible.

Therefore, the transients and transient occurrences that were assumed in the original analysis remain valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The emergency condenser steam isolation valves fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7.4.3 EMERGENCY CONDENSER CONDENSATE RETURN CHECK VALVES FATIGUE ANALYSIS

TLAA Description:

The Nine Mile Point Nuclear Station, Unit 1 (NMP1) emergency condenser condensate return check valves (CKV-39-03 and CKV-39-04) were replaced in 1995 and designed in accordance with ASME Section III, 1986 Edition. The internals of CKV-39-04 were replaced in 2003 and were designed in accordance with ASME Section III, Subsection NB, 1986 Edition. These check valves are not ASME Class 1 components, and while a fatigue analysis is not required, fatigue analyses were provided for the replaced check valves using the guidance of the ASME code.

The design analyses for both valves evaluated fatigue in accordance with ASME Section III, 1986, Subsection NB-3500, "Valve Design," and demonstrated compliance with the acceptance criteria for normal duty valve fatigue requirements in accordance with NB-3545.3, by determining an allowable number of $1.0\text{E}+6$ cycles, against an applied 2,000 cycles of startup and shutdown transients.

Since the emergency condenser condensate return check valves design analyses demonstrated fatigue acceptance of the valves using transients and transient occurrences assumed to occur over the life of the plant, these analyses have been identified as a TLAA that must be evaluated for the subsequent period of extended operation.

TLAA Evaluation:

The analyses both considered an applied 2,000 cycles of normal duty operational cycles (100 degree F/hour change rate) corresponding to startup and shutdown transients. Check Valves CKV-39-03 and CKV-39-04 would experience these thermal cycles along with the reactor (startup and shutdown transients) and it is also assumed that the check valves will experience normal duty operation cycles associated with the emergency condenser system specific transients.

SLRA Table 4.3.1-1 documents 80-year transient projections for normal startup (transient number 4), normal shutdown (transient number 6), emergency condenser (stop actuation) (transient number 31), emergency condenser (subsequent actuation) (transient number 30), emergency condenser initiation into idle loop (transient number 14), emergency condenser initiation into isolated loop (transient number 12), and emergency condenser into pumped loop (transient number 17). SLRA Table 4.3.1-1 demonstrates that the projected 80-year occurrences for these transients summed together is 860, which is less than the postulated 2,000 occurrences defined by ASME Section III, NB-3545.3.

Therefore, the transients and transient occurrences that were assumed in the original analyses remain valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The emergency condenser condensate return check valves fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7.5 ERV VACUUM BREAKER VALVE FATIGUE ANALYSIS

TLAA Description:

There are two 10-inch vacuum breaker swing check valves (CKV-66-25 through CKV-66-36) installed on each of the six electromatic relief valve (ERV) discharge lines into the torus. Each of the twelve 10-inch ERV vacuum breaker valves were modified to prevent failures of the disk hinge arms during valve actuation after CKV-66-26 had failed during the Nine Mile Point Nuclear Station, Unit 1 (NMP1) restart of fall 2000. The vacuum breaker valves are ASME Class 3 components, and while an ASME Code fatigue analysis is not required, fatigue evaluations using the guidance of the ASME code were provided for the modified vacuum breaker valve subcomponents that are affected by cyclic impact loads to assess the adequacy of the design.

The fatigue analyses of the modified ERV vacuum breaker valves each assumed 7,000 cycles of “Full ERV Discharge during Normal Operation,” and 1,000,000 cycles of “Leaking ERV at Low Reactor Pressure.” The resulting fatigue analyses applied these transients to each of the vacuum breaker valve pressure boundary and internal components and determined a maximum cumulative usage factor (CUF) of 0.07.

Since these analyses resulted in calculated CUF values using transients and transient occurrences assumed to occur over the life of the plant, these analyses have been identified as a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

SLRA Table 4.3.1-1 documents that the maximum 80-year projected transient occurrences of any of the six individual ERV discharge lines is 94 (transient number 29b), and the total number of projected transient occurrences for all ERVs combined is 492 (transient number 29). Therefore, adequate margin remains in the 7,000 ERV actuations that were assumed in the analyses. Fatigue due to the postulated “Leaking ERV at Low Reactor Pressure” transient is negligible as the number of cycles postulated is beyond the endurance limit of the ASME fatigue curves. Therefore, the transients and transient occurrences that were assumed in the original analyses remain valid for the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The ERV vacuum breaker valve fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7.6 CORE SPRAY SYSTEM WELD FATIGUE FLAW GROWTH ANALYSIS

TLAA Description:

A fatigue flaw growth analysis was performed in 1999 to evaluate the acceptability of non-destructive examination (NDE) indications found in weld number 81-WD-059 in the core spray pump suction line from the condensate storage tank between valves VLV-81-37 and VLV-81-38. The NDE indications were determined to have originated during the original welding process. Since the indications in weld number 81-WD-059 did not meet the screening criteria of ASME, Subsection IWB-3500, a fatigue flaw growth analysis was performed using the guidance of ASME Section XI, 1995 Edition, IWB-3600 and Appendix H criteria was performed.

The analysis assumed a total of 200 cycles comprised of 100 seismic loading cycles and 100 pressure cycles due to testing of the core spray line during refueling outages. The analysis concluded that the weld indications were acceptable without requiring repair or modification based on the determined final flaw sizes under normal operating conditions and emergency/faulted conditions.

Since this analysis assumed cracking in a portion of the weld and used transient and transient occurrences assumed to occur over the life of the plant, this evaluation is considered a TLAA that must be considered for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

SLRA Table 4.3.1-1 documents that one operating basis earthquake (OBE) (transient number 28) is projected for 80 years. Nine Mile Point Nuclear Station, Unit 1 (NMP1) has not experienced an OBE, and the assumed 100 seismic cycles are bounding during the SPEO.

The line of the core spray system analyzed is used for testing one core spray pump set in each loop with suction from the condensate transfer system, as valves VLV-81-37 and VLV-81-38 are locked closed during normal operation. This test is performed by drawing water from the condensate system and pumping to the reactor vessel during each refueling outage (RFO). Prior to entering the SPEO, NMP1 will have performed 30 RFO's. The NMP1 reactor operates on a 24-month refueling cycle, therefore 10 more RFO's or pressurization cycles for testing of the core spray line analyzed can be expected at the end of the SPEO, for a total of 40 pressurization cycles over 80 years. Therefore, the 100 pressure cycles assumed in the flaw analysis remain bounding for 80 years.

Therefore, adequate margin remains in the 200 cycles assumed in the analysis of core spray weld number WD-81-059, and the flaw growth analysis remains valid for 80 years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The core spray system weld fatigue flaw growth analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7.7 CRD BOTTOM HEAD PENETRATIONS FRACTURE MECHANICS ANALYSIS

TLAA Description:

Nine Mile Point Nuclear Station, Unit 1 (NMP1) has control rod drive (CRD) reactor pressure vessel (RPV) bottom head penetrations that have leaked due to intergranular stress corrosion cracking (IGSCC) in the furnace sensitized stainless steel stub tubes. For CRD penetrations that have leaked, a roll-expansion repair method to eliminate leakage has been implemented since 1984. As part of the first license renewal application, NMP1 committed to implement a zero leakage roll repair method for leaking CRD penetrations utilizing ASME Section XI, Code Case N-730, "Roll-Expansion of Class 1 Control Rod Drive (CRD) Bottom Head Penetrations in BWRs, Section XI, Division 1," as accepted by the NRC Safety Evaluation Report (Reference 4.8.49). To demonstrate compliance with the technical requirements of code case N-730, a comparative fracture mechanics evaluation was performed. The evaluation compared key parameters of the NMP1 CRD penetrations against the parameters provided in the generic fracture mechanics evaluation contained in the technical-basis document for Code Case N-730: BWRVIP-146NP, Revision 1. The generic fracture mechanics analysis evaluated a postulated crack in the stub tube-to-vessel attachment weld and considered both fatigue and stress corrosion cracking, concluding that crack growth due to these two factors would be much less than ASME acceptance criteria.

The NMP1 comparative analysis demonstrated acceptance in accordance with the generic analysis for 60 years and demonstrated that the 60-year projected transient occurrences were less than the postulated transient occurrences from the generic analysis. The NMP1 comparative analysis demonstrated that the NMP1 CRD bottom head penetrations are bounded by the generic analysis and concluded that sufficient fracture margins exist for a 60-year plant life, as accepted by the NRC.

Since this analysis postulated a flaw in the attachment weld and considered transient and transient occurrences assumed to occur over the life of the plant, this evaluation is considered a TLAA that must be considered for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

The CRD bottom head penetration fracture mechanic comparative analysis has been reevaluated for the SPEO. The fracture mechanics parameters in the comparative fracture mechanics evaluation remain acceptable as the NMP1 fracture margin remains higher than the value in the generic analysis and the 80-year total number of transient occurrences remains less than the number of cycles postulated in the generic assessment. Therefore, the parameters of the NMP1 CRD bottom head penetration fracture mechanics comparative analysis remain bounded by those of the generic fracture mechanics analysis for the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii) – The CRD bottom head penetrations fracture mechanics analysis has been successfully projected through the subsequent period of extended operation.

4.7.8 CRANE CYCLIC LOADING ANALYSES

TLAA Description:

A review of the Nine Mile Point Nuclear Station, Unit 1 (NMP1) current licensing basis for cranes within the scope of subsequent license renewal was performed to identify those cranes that were designed or meet the intent of Crane Manufacturers Association of America (CMAA) Specification 70. The NMP1 reactor building crane, turbine building crane, and greenhouse crane meet the intent of CMAA Specification 70 as determined in the responses to NUREG-0612 (Reference 4.8.50), as guided by NRC Generic Letter 81-07 (Reference 4.8.51).

CMAA Specification 70 includes considerations for frequency of operation and expected load sizes relative to their maximum load capacity. Based on these considerations, cranes are designed for a given service class classification with an expected maximum number of design load cycles over their life, which also correlates to a number of load cycles on structural members.

Since the maximum number of load cycles over the life of the cranes, specified in CMAA Specification 70, provides a basis for acceptability for fatigue over the life of these cranes, the underlying basis is considered a TLAA that must be evaluated for the subsequent period of extended operation (SPEO).

TLAA Evaluation:

Reactor Building Crane

The 125-ton reactor building crane was designed consistent with the guidance in CMAA Specification 70 and is considered a “Class A” crane experiencing “irregular occasional use followed by long idle periods.” For this designation, the specification allows between 20,000 and 100,000 load cycles. Therefore, 20,000 load cycles is a conservative threshold. Load cycles that lift less than 50 percent of the crane design capacity of 125 tons (62.5 tons) result in minimal fatigue on the crane. Therefore, load cycles that lift 50 tons or more were evaluated for this TLAA.

SLRA Table 4.7.8-1 provides 80-year heavy lift projections for the reactor building crane. The number of heavy lift cycles projected for 80 years of operation is 3,160 cycles which is approximately 15.8 percent of the 20,000-cycle conservative threshold. Therefore, the fatigue analysis for the reactor building crane remains valid for 80 years of plant operation.

Table 4.7.8-1 Nine Mile Point Nuclear Station, Unit 1 Reactor Building Crane Load Cycles			
Heavy Load Description	Frequency (Note 1)	Number of Years	Number of Lifts over 80 years
Plant Construction Cycles	NA	NA	500
Shield Plugs (51 – 122 tons)	14/year	80	1,120
Drywell Head (54 tons)	2/year	80	160
Reactor Head with Strongback Lifting Device (104.2 tons)	2/year	80	160
ISFSI Casks (>62.5 tons) ⁽²⁾ (through the year 2049 – 6 lifts per cask)	150 casks, 6 cycles per cask over 80 years	NA	900
Miscellaneous	4/year	80	320
Total for 80 Years			3,160
Minimum Design Limit			20,000
Percent of Load Cycle Limit at 80 Years			15.8%

Note 1: Frequencies conservatively assume an annual refueling outage, unless noted otherwise.

Note 2: All ISFSI casks are assumed to weigh greater than 62.5 tons.

Turbine Building Crane

The 150-ton turbine building crane was designed to Electrical Overhead Crane Institute (EOCI) Specification No. 61 but was found to meet the intent of CMAA Specification 70 in NMP1 responses to NUREG-0612. The 150-ton turbine building crane has also been evaluated for a 170-ton load and Class A service per CMAA Specification 70 for a planned engineered lift. Therefore, the 150-ton turbine building crane is considered a “Class A” crane experiencing “irregular occasional use followed by long idle periods.” For this designation, the specification allows between 20,000 and 100,000 load cycles. Therefore, 20,000 load cycles is a conservative threshold. Load cycles that lift less than 50 percent of the crane design capacity of 150 tons (75 tons) result in minimal fatigue on the crane. Therefore, load cycles that lift 60 tons or more were evaluated for this TLAA.

SLRA Table 4.7.8-2 provides 80-year heavy lift projections for the turbine building crane. The number of heavy lift cycles projected for 80 years of operation is 716 cycles which is approximately 3.6 percent of the 20,000-cycle conservative threshold. Therefore, the fatigue analysis for the turbine building crane remains valid for 80 years of plant operation.

Table 4.7.8-2 Nine Mile Point Nuclear Station, Unit 1 Turbine Building Crane Load Cycles			
Heavy Load Description	Frequency (Note 1)	Number of Years	Number of Lifts over 80 years
Plant Construction Cycles			500
Generator Rotor (168.8 tons)	2/6 years	80	27
HP Turbine Outer Shell (Upper) (74 tons)	2/6 years	80	27
HP Turbine Rotor with Lifting Beam (72.5 tons)	2/6 years	80	27
LP Turbine A Rotor with Lifting Beam (119 tons)	2/6 years	80	27
LP Turbine B Rotor with Lifting Beam (119 tons)	2/6 years	80	27
LP Turbine B Rotor with Lifting Beam (119 tons)	2/6 years	80	27
Miscellaneous	4/6 years	80	54
Total for 80 Years			716
Minimum Design Limit			20,000
Percent of Load Cycle Limit			3.6%

Note 1: Frequencies conservatively assume recommended turbine and generator maintenance schedules.

Screenhouse Building Crane

The 25-ton screenhouse building crane was designed to EOCI-61 but was found to meet the intent of CMAA Specification 70 in NMP1 responses to NUREG-0612. While EOCI-61 does not explicitly address fatigue failure, since the 25-ton screenhouse crane was stated to meet the intent of CMAA Specification 70, it is evaluated as a CMAA Specification 70 “Class A” crane experiencing “irregular occasional use followed by long idle periods.” For this designation, the specification allows between 20,000 and 100,000 load cycles. Therefore, 20,000 load cycles is a conservative threshold. Load cycles that lift less than 50 percent of the crane design capacity of 25 tons (12.5 tons) result in minimal fatigue on the crane. Therefore, load cycles that lift 10 tons or more were evaluated for this TLAA.

SLRA Table 4.7.8-3 provides 80-year heavy lift projections for the screenhouse building crane. The number of heavy lift cycles projected for 80 years of operation is 1,380 cycles which is approximately 6.9 percent of the 20,000-cycle conservative threshold. Therefore, the fatigue analysis for the screenhouse building crane remains valid for 80 years of plant operation.

Table 4.7.8-3 Nine Mile Point Nuclear Station, Unit 1 Screenhouse Building Crane Load Cycles			
Heavy Load Description	Frequency (Note 1)	Number of Years	Number of Lifts over 80 years
Plant Construction Cycles			500
Circulating Water Pump Motor (18.5 tons)	2/year	80	160
Traveling Water Screens (10.3 tons)	5/year	80	400
Miscellaneous	4/year	80	320
Total for 80 Years			1,380
Minimum Design Limit			20,000
Percent of Load Cycle Limit			6.9%

Note 1: Frequencies are conservatively based on operating experience.

TLAA Disposition: 10 CFR 54.21(c)(1)(i) – The projected number of load cycles associated with the reactor building crane, turbine building crane, and screenhouse crane are considerably less than the specified acceptance criteria. Therefore, this TLAA remains valid through the subsequent period of extended operation.

4.7.9 CORE SHROUD TIE ROD X-750 INCONEL COMPONENT SERVICE LIFE

TLAA Description:

In 1995, Nine Mile Point Nuclear Station, Unit 1 (NMP1) installed four core shroud tie-rod assemblies (tie-rods) as a repair in response to cracks that were identified on the core shroud horizontal welds. These assemblies included subcomponents made of X-750 Inconel. In 2007, the top portion of all four tie-rods, including the “top nuts” which are fabricated from X-750 material were replaced after the potential for high peak stresses in the original shroud stabilizer upper support design was discovered.

In January 2007, GE Energy issued a Safety Information Communication Letter to applicable stations related to the potential for intergranular stress corrosion cracking (IGSCC) of core shroud repair tie-rod subcomponents fabricated from X-750 Inconel. The letter concluded that threaded subcomponents with calculated stresses less than 78 percent of yield strength have a 40-year service life. This letter did not document a service life for threaded X-750 components beyond 40 years. For nonthreaded components, BWRVIP-84, Revision 2-A requires the sustained stress level under normal operating conditions to not exceed 70 percent of the ASME Code or certified material test report minimum yield strength of the material at the intended operating temperature for a 40-year design. BWRVIP-84, Revision 2-A does not document an allowable stress ratio for a design life beyond 40 years.

In 2007, GE provided NMP1 with additional proprietary reports which documented the calculated stresses for all NMP1 tie-rod subcomponents fabricated from X-750 material.

Three threaded X-750 subcomponent types exceeded the 78 percent threshold, and one non-threaded X-750 subcomponent exceeded the 70 percent threshold.

In addition, in 2007, GE provided NMP1 with proprietary reports which justified a 40-year service life for threaded and non-threaded X-750 subcomponents in which the calculated stress exceeded 70 or 78 percent of yield stress.

Since these GE reports evaluate the aging effect of IGSCC cracking on tie-rod X-750 subcomponents over a 40-year service life and the NMP1 subsequent period of extended operation (SPEO) will end in 2049, these GE reports have been identified as a TLAA that must be evaluated for the SPEO.

TLAA Evaluation:

The NMP1 BWR Vessel Internals (B.2.1.7) program specifies that materials used for repairs or replacements meet the guidelines of BWRVIP-84, Revision 2-A, as modified by BWRVIP Letter 2011-011, “Guidance for Evaluating Repair Hardware with X-750 Components.”

As a result, the NMP1 BWR Vessel Internals (B.2.1.7) program will be enhanced to develop a justification for the service life through the SPEO, consistent with BWRVIP-94, Revision 4, which may include supplemental inspections, inspection frequencies, and technical evaluations to validate that tie-rod X-750 subcomponents can perform their intended function through the SPEO. This enhancement will be

implemented no later than six months prior to the SPEO. Therefore, this TLAA will be managed by the NMP1 BWR Vessel Internals (B.2.1.7) program through the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii) – The effects of IGSCC cracking on the intended function(s) of the core shroud tie-rod assembly subcomponents fabricated from X-750 Inconel will be managed by the BWR Vessel Internals (B.2.1.7) program through the SPEO. The BWR Vessel Internals (B.2.1.7) program will manage this TLAA and associated effects of IGSCC on the core shroud tie-rod assemblies through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.8 REFERENCES

- 4.8.1 *Nine Mile Point Nuclear Station, Unit 1 – Final Safety Analysis Report (Updated), Revision 28 (Sections 4.2.1, 4.2.7, 4.3.1, 4.3.2, 4.3.3, 4.3.4, 4.3.6.1, 4.3.6.2, 4.4.1, 4.6, 4.6.1, 4.6.2, 4.6.3, 4.6.6, 4.6.8, 4.6.9, 4.7.2, 4.7.6, 4.7.7, 4.7.8, and 4.7.9)*
- 4.8.2 *10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants (Section 4.1)*
- 4.8.3 *NUREG-2192, Revision 1, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP) (Sections 4.1.1, 4.2, 4.2.4, 4.3, and 4.7.3)*
- 4.8.4 *NUREG-2191, Revision 1, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (Sections 4.1.1, 4.3.1, 4.3.5, and 4.4.1)*
- 4.8.5 *NEI 95-10, Revision 6, Industry Guideline for Implementing the Requirements of 10 CFR 54, the License Renewal Rule (Section 4.1)*
- 4.8.6 *NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal (Section 4.1.1)*
- 4.8.7 *10 CFR 50.60, Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation (Section 4.2)*
- 4.8.8 *10 CFR 50, Appendix G, Fracture Toughness Requirements (Sections 4.2, 4.2.2, 4.2.3, and 4.2.4)*
- 4.8.9 *10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements (Section 4.2)*
- 4.8.10 *Nine Mile Point Nuclear Station, Unit 1 letter dated April 20, 1970, transmitting "Petition Requesting Amendment of License" and "Technical Supplement to Petition to Increase Power Level" (ML17037C382) (Section 4.2.1)*
- 4.8.11 *NRC letter dated March 3, 1971, Nine Mile Point Nuclear Station Unit 1, Issuance of Amendment, Authorizing Operation at Power Levels Up to 1850 Megawatts (Thermal) (ML010960437) (Section 4.2.1)*
- 4.8.12 *Nine Mile Point Nuclear Station, Unit 1 letter dated April 13, 2017, Nine Mile Point, Unit 1 - Pressure and Temperature Limits Report (ML17109A365) (Section 4.2.1.1)*
- 4.8.13 *NRC Regulatory Guide 1.162, Format and Content of Report for Thermal Annealing of Reactor Pressure Vessels, February 1996 (Section 4.2.2)*
- 4.8.14 *NRC Regulatory Guide 1.99, Revision 2, Radiation Embrittlement of Reactor Vessel Materials, Revision 2, May 1988 (Sections 4.2.2, and 4.2.3)*
- 4.8.15 *NRC Branch Technical Position 5-3, Draft Revision 3, Fracture Toughness Requirements (Section 4.2.3)*

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- 4.8.16 *Nine Mile Point Nuclear Station, Unit 1, Technical Specifications 6.6.7, Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR) (Section 4.2.4)*
- 4.8.17 *NRC letter dated August 3, 2009, Nine Mile Point Nuclear Station, Unit No.1 - Request to Use Alternative for Volumetric Examination of Reactor Pressure Vessel Circumferential Shell Welds for the License Renewal Period of Extended Operation (TAC No. MD9704) (ML092010256) (Sections 4.2.5, and 4.2.6)*
- 4.8.18 *NRC Generic Letter 98-05, Boiling Water Reactor Licensees Use of the BWRVIP-05 Report to Request Relief from Augmented Examination Requirements on Reactor Pressure Vessel Circumferential Shell Welds, November 10, 1998 (Section 4.2.5)*
- 4.8.19 *NRC letter dated July 28, 1998, Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report, (TAC No. M93925) (ML20236V551) (Section 4.2.5)*
- 4.8.20 *NUREG/CR-6260, Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components, March 1995 (Sections 4.3.1, 4.3.2, and 4.3.5)*
- 4.8.21 *Nine Mile Point Nuclear Station letter dated July 14, 2005, Nine Mile Point - Amended License Renewal Application, Technical Information (ML052000186) (Sections 4.3.2, 4.3.3, 4.3.6.1, 4.3.6.2, 4.6.1, 4.6.2, 4.6.3, 4.6.4.1, 4.6.4.2, 4.7.1.1, 4.7.1.2, and 4.7.3)*
- 4.8.22 *NUREG-1900, Volume 2, Safety Evaluation Report Related to the License Renewal of Nine Mile Point Nuclear Station, Units 1 and 2 (Sections 4.3.3, 4.3.6, 4.3.6.1, 4.6.1, 4.6.3, 4.7.1.2, 4.7.2, and 4.7.3)*
- 4.8.23 *Nine Mile Point Nuclear Station, Unit 1 letter dated January 30, 1998, LER 97-010, Supplement 1, "Technical Specification Required Shutdown Due to Emergency Cooling Condenser Tube Leak" (ML17059B839) (Section 4.3.3)*
- 4.8.24 *NUREG-1800, Revision 2, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (Section 4.3.4)*
- 4.8.25 *NRC IN-89-55, Degradation of Containment Isolation Capability by a High-Energy Line Break, June 30, 1989 (Section 4.3.4)*
- 4.8.26 *NRC Generic Letter 87-11, "Relaxation in Arbitrary Intermediate Pipe Rupture Requirements" and SRP 3.6.2, BTP MEB 3-1, Revision 2, "Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment." (Section 4.3.4)*
- 4.8.27 *NUREG/CR-6583, Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels, February 1998 (Section 4.3.5)*
- 4.8.28 *NUREG/CR-5704, Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels, April 1999 (Section 4.3.5)*
- 4.8.29 *NUREG/CR-6909, Revision 0, Effect of LWR Water Environments on the Fatigue Life of Reactor Materials, February 2007 (Section 4.3.5)*
- 4.8.30 *NUREG/CR-6909, Revision 1, Effect of LWR Water Environments on the Fatigue Life of Reactor Materials, May 2018 (Section 4.3.5)*

- 4.8.31 *NRC letter dated October 3, 2007, Nine Mile Point Nuclear Station, Unit No. 1 – Authorization Under 10 CFR 50.55a(a)(3)(i) for Modification of Core Shroud Stabilizer Assemblies (TAC NO. MD4417) (ML072600195) (Sections 4.3.6.3, and 4.7.9)*
- 4.8.32 *NUREG-0661, Safety Evaluation Report Mark I Containment Long-Term Program Resolution of Generic Technical Activity A-7, July 1980 (Sections 4.6, and 4.6.1)*
- 4.8.33 *MPR-751, Mark I Containment Program Augmented Class 2/3 Fatigue Evaluation Method & Results for Typical Torus Attached & Safety Relief Valve Piping Systems, November 1982 (ML20070A040) (Sections 4.6.3, 4.6.4.1, 4.6.4.2, and 4.6.5)*
- 4.8.34 *Nine Mile Point Nuclear Station letter dated December 6, 2004, License Renewal Application - Responses to NRC Requests for Additional Information Regarding Time-Limited Aging Analyses (TAC Nos. MC0691 and MC0692) (ML043500312) (Section 4.6.3)*
- 4.8.35 *Nine Mile Point Nuclear Station letter dated July 14, 2005, License Renewal Application - Responses to Previously Unanswered NRC Requests for Additional Information (TAC Nos. MC3272 and MC3273) (ML052000147) (Section 4.6.3)*
- 4.8.36 *NEDO-24583, Revision 1, Mark I Containment Program Structural Acceptance Criteria, Plant Unique Analysis Application Guide, October 1979 (ML19257A791) (Section 4.6.4.2, and 4.6.5)*
- 4.8.37 *NRC letter dated July 29, 2008, Nine Mile Point Nuclear Station, Unit No. 1 – Additional Engineering Evaluations for Two Reactor Pressure Vessel Weld Flaws in Accordance with Amended License Renewal Application Commitment (TAC NO. MD6620) (ML082040528) (Section 4.7.1.1)*
- 4.8.38 *NRC letter dated July 2, 2012, Nine Mile Point Nuclear Station, Unit No. 1 Re: NRC Approval of Reactor Pressure Vessel Head Weld Flaw Evaluation (ML12180A267) (Section 4.7.1.2)*
- 4.8.39 *Nine Mile Point Nuclear Station, Unit 1 letter dated November 30, 2012, Reactor Pressure Vessel Head Weld Flaw Evaluation - Clarification Regarding Subsequent Examination of the Weld Flaw Indication (ML12342A323) (Section 4.7.1.2)*
- 4.8.40 *NUREG-0619, Revision 1, BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking: Resolution of Generic Technical Activity A-10, November 1980 (Section 4.7.3)*
- 4.8.41 *NRC Generic Letter 81-11, BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking (NUREG-0619) (Section 4.7.3)*
- 4.8.42 *Nine Mile Point Nuclear Station, Unit 1 letter dated November 16, 1977, Summary Report-1977 Feedwater Sparger Replacement Project-Nine Mile Point Nuclear Station Unit 1 (Legacy Accession Number 4008006592) (Section 4.7.3)*
- 4.8.43 *Second Inservice Inspection Interval Third Inspection Period NUREG-0619 Inspection Reporting for RPV Feedwater and C Nozzle Examinations - 1999 Refueling Outage (RFO-15) (ML993550381) (Section 4.7.3)*

- 4.8.44 *Nine Mile Point Nuclear Station, Unit 1 letter dated June 23, 1994, NUREG-0619, BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking Commitment Change (Legacy Accession Number 9407010157) (Section 4.7.3)*
- 4.8.45 *BWR Owners' Group letter BWROG-95092 dated October 30, 1995, Alternate BWR Feedwater Nozzle Inspection Requirements (contains GE-NE-523-A71-0594, Alternate BWR Feedwater Nozzle Inspection Requirements) (ML20094D891) (Section 4.7.3)*
- 4.8.46 *Nine Mile Point Nuclear Station, Unit 1 letter dated September 4, 1998, NUREG-0619, BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking Commitment Change (ML17059C233) (Section 4.7.3)*
- 4.8.47 *NRC Safety Evaluation Report Regarding an Alternative to NUREG-0619 for Inspecting Feedwater and Control Rod Drive Return Line Nozzles, Nine Mile Point Nuclear Station, Unit 1, dated February 5, 1999 (ML20203B511) (Section 4.7.3)*
- 4.8.48 *Nine Mile Point Nuclear Station, Unit 1 letter dated August 29, 2008, Request to Utilize an Alternative to the Requirements of 10 CFR 50.55a(g) for the Repair and Inservice Inspection of Control Rod Drive Stub Tubes for the License Renewal Period of Extended Operation (ML082530250) (Section 4.7.7)*
- 4.8.49 *NRC letter dated August 3, 2009, Nine Mile Point Nuclear Station, Unit No. 1 - Request to Utilize Alternative of Applying ASME Code Case N-730 for Repair and Inservice Inspection of Control Rod Drive Bottom Head Penetrations for the License Renewal Period of Extended Operation (TAC No. MD9604) (ML091980454) (Section 4.7.7)*
- 4.8.50 *NUREG-0612, Control of Heavy Loads at Nuclear Power Plants: Resolution of Generic Technical Activity A-36, July 1980 (Section 4.7.8)*
- 4.8.51 *NRC Generic Letter 81-07, Control of Heavy Loads (Section 4.7.8)*
- 4.8.52 *Nine Mile Point Nuclear Station, Unit 1 letter dated November 15, 1983, Final Response to Franklin Research Center Draft Technical Evaluation Report Providing Recommendations to Achieve Compliance with NUREG-0612, Sections 5.1.1 and 5.3 (ML17054A223) (Section 4.7.8)*
- 4.8.53 *Nine Mile Point Nuclear Station, Unit 1 letter dated November 25, 1985, Results of Two Revised Load Drop Analyses and Screenhouse Crane Design Review (ML17055A817) (Section 4.7.8)*
- 4.8.54 *NRC letter dated November 29, 2000, Nuclear Energy Institute (NEI) Additional Comments on Generic Aging Lessons Learned (GALL) Report – Mechanical Systems (contains Electric Overhead Crane Institute (EOCI) Specification # 61 - Specifications for Electric Overhead Traveling Cranes) (ML003772481) (Section 4.7.8)*
- 4.8.55 *Technical Evaluation Report TER-C5506-371, Control of Heavy Loads, Nine Mile Point Unit 1 (ML20101T372) (Section 4.7.8)*
- 4.8.56 *NRC letter dated March 31, 1995, Nine Mile Point Nuclear Station Unit No. 1 (NMP1), Evaluation of Core Shroud Stabilizer Design (TAC NO. M91273) (ML17059A774) (Section 4.7.9)*

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A.1.0 Introduction

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a UFSAR Supplement. This appendix, which includes the following sections, comprises the UFSAR Supplement:

- Section A.1.1 contains a listing of the aging management programs that correspond to NUREG-2191 Chapter XI programs, including the status of the programs at the time the Subsequent License Renewal Application was submitted.
- Section A.1.2 contains a listing of the plant-specific aging management programs, including the status of the programs at the time the Subsequent License Renewal Application was submitted.
- Section A.1.3 contains a listing of aging management programs that correspond to NUREG-2191 Chapter X programs associated with Time-Limited Aging Analyses, including the status of the programs at the time the Subsequent License Renewal Application was submitted.
- Section A.1.4 contains a listing of the Time-Limited Aging Analyses summaries (TLAAs).
- Section A.1.5 contains a discussion of the Quality Assurance Program and Administrative Controls.
- Section A.1.6 contains a discussion of the Operating Experience.
- Section A.2 contains a summarized description of the aging management programs.
- Section A.2.1 contains a summarized description of the NUREG-2191 Chapter XI programs for managing the effects of aging.
- Section A.2.2 contains a summarized description of the plant-specific programs for managing the effects of aging.
- Section A.3 contains a summarized description of the NUREG-2191 Chapter X programs that support the TLAAs.
- Section A.4 contains a summarized description of the TLAAs applicable to the subsequent period of extended operation.
- Section A.5 contains the Subsequent License Renewal Commitment List.

The integrated plant assessment for license renewal identified new and existing aging management programs necessary to provide reasonable assurance that systems, structures, and 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. The subsequent period of extended operation is defined as 20 years from the unit's current renewed operating license expiration date.

A.1.1 NUREG-2191 Chapter XI Aging Management Programs

The NUREG-2191 Chapter XI Aging Management Programs (AMPs) are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements.

The following list reflects the status of these programs at the time of the Subsequent License Renewal Application (SLRA) submittal. Commitments for program additions and enhancements are identified in the Appendix A.5 Subsequent License Renewal Commitment List.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section A.2.1.1) [Existing]
2. Water Chemistry (Section A.2.1.2) [Existing]
3. Reactor Head Closure Stud Bolting (Section A.2.1.3) [Existing]
4. BWR Vessel ID Attachment Welds (Section A.2.1.4) [Existing]
5. BWR Stress Corrosion Cracking (Section A.2.1.5) [Existing]
6. BWR Penetrations (Section A.2.1.6) [Existing]
7. BWR Vessel Internals (Section A.2.1.7) [Existing – Requires Enhancement]
8. Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section A.2.1.8) [New]
9. Flow-Accelerated Corrosion (Section A.2.1.9) [Existing - Requires Enhancement]
10. Bolting Integrity (Section A.2.1.10) [Existing - Requires Enhancement]
11. Open-Cycle Cooling Water System (Section A.2.1.11) [Existing - Requires Enhancement]
12. Closed Treated Water Systems (Section A.2.1.12) [Existing - Requires Enhancement]
13. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section A.2.1.13) [Existing – Requires Enhancement]
14. Compressed Air Monitoring (Section A.2.1.14) [Existing – Requires Enhancement]
15. Fire Protection (Section A.2.1.15) [Existing – Requires Enhancement]
16. Fire Water System (Section A.2.1.16) [Existing – Requires Enhancement]
17. Not used.
18. Fuel Oil Chemistry (Section A.2.1.18) [Existing – Requires Enhancement]

19. Reactor Vessel Material Surveillance (Section A.2.1.19) [Existing – Requires Enhancement]
20. One-Time Inspection (Section A.2.1.20) [New]
21. Selective Leaching (Section A.2.1.21) [New]
22. ASME Code Class 1 Small-Bore Piping (Section A.2.1.22) [New]
23. External Surfaces Monitoring of Mechanical Components (Section A.2.1.23) [New]
24. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section A.2.1.24) [New]
25. Lubricating Oil Analysis (Section A.2.1.25) [Existing – Requires Enhancement]
26. Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section A.2.1.26) [Existing]
27. Buried and Underground Piping and Tanks (Section A.2.1.27) [Existing – Requires Enhancement]
28. Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section A.2.1.28) [New]
29. ASME Section XI, Subsection IWE (Section A.2.1.29) [Existing – Requires Enhancement]
30. ASME Section XI, Subsection IWF (Section A.2.1.30) [Existing – Requires Enhancement]
31. 10 CFR Part 50, Appendix J (Section A.2.1.31) [Existing]
32. Masonry Walls (Section A.2.1.32) [Existing – Requires Enhancement]
33. Structures Monitoring (Section A.2.1.33) [Existing – Requires Enhancement]
34. Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section A.2.1.34) [Existing – Requires Enhancement]
35. Protective Coating Monitoring and Maintenance (Section A.2.1.35) [Existing – Requires Enhancement]
36. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.36) [Existing – Requires Enhancement]
37. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section A.2.1.37) [Existing – Requires Enhancement]

38. Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.38) [Existing – Requires Enhancement]
39. Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.39) [New]
40. Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.40) [New]
41. Metal Enclosed Bus (Section A.2.1.41) [Existing – Requires Enhancement]
42. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.42) [New]

A.1.2 Plant-Specific Aging Management Programs

None. The Nine Mile Point Nuclear Station, Unit 1 Subsequent License Renewal Application does not include plant-specific aging management programs.

A.1.3 NUREG-2191 Chapter X Aging Management Programs

The NUREG-2191 Chapter X Aging Management Programs (AMP) associated with Time-Limited Aging Analyses are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 Chapter X or require enhancements. The following list reflects the status of these programs at the time of the Subsequent License Renewal Application (SLRA) submittal. Commitments for program additions and enhancements are identified in Appendix A.5 Subsequent License Renewal Commitment List.

1. Fatigue Monitoring (Section A.3.1.1) [Existing]
2. Neutron Fluence Monitoring (Section A.3.1.2) [Existing]
3. Environmental Qualification of Electric Equipment (Section A.3.1.3) [Existing – Requires Enhancement]

A.1.4 Time-Limited Aging Analyses

Summaries of the Time-Limited Aging Analyses applicable to the subsequent period of extended operation are included in the following sections:

1. Reactor Pressure Vessel and Internals Neutron Embrittlement Analyses (Section A.4.2)
2. Neutron Fluence Analyses (Section A.4.2.1)
3. Reactor Pressure Vessel Neutron Fluence Analyses (Section A.4.2.1.1)
4. Reactor Pressure Vessel Internals Neutron Fluence Analyses (A.4.2.1.2)

5. Reactor Pressure Vessel Upper-Shelf Energy (USE) Analyses (Section A.4.2.2)
6. Reactor Pressure Vessel Adjusted Reference Temperature (ART) Analyses (Section A.4.2.3)
7. Reactor Pressure Vessel Pressure-Temperature (P-T) Limits (Section A.4.2.4)
8. Reactor Pressure Vessel Circumferential Weld Failure Probability Analysis (Section A.4.2.5)
9. Reactor Pressure Vessel Axial Weld Failure Probability Analysis (Section A.4.2.6)
10. Core Shroud Stabilizer Assembly Preload Relaxation Analysis (Section A.4.2.7)
11. Metal Fatigue Analyses (Section A.4.3)
12. Transient Cycle and Cumulative Usage Projections for 80 Years (Section A.4.3.1)
13. Reactor Vessel and Piping Fatigue Analyses (Section A.4.3.2)
14. Fatigue of Emergency Condensers (Section A.4.3.3)
15. ASME Section III, Class 2 and 3, and ANSI B31.1 Allowable Stress Analyses and HELB Exclusions of Recirculation Piping Analysis (Section A.4.3.4)
16. Environmentally Assisted Fatigue Analysis (Section A.4.3.5)
17. Reactor Vessel Internals Fatigue Analyses (Section A.4.3.6)
18. Core Shroud Stabilizer Tie Rod and Conical Support Fatigue Analysis (A.4.3.6.1)
19. Core Shroud Vertical Weld Repair Clamps Fatigue Analysis (Section A.4.3.6.2)
20. Core Shroud Stabilizer Modified Upper Supports Fatigue Analyses (Section A.4.3.6.3)
21. Environmental Qualification of Electric Equipment (Section A.4.4.1)
22. Concrete Containment Tendon Prestress Analyses (A.4.5)
23. Primary Containment Fatigue Analyses (Section A.4.6)
24. Torus Shell Fatigue Analysis (Section A.4.6.1)
25. Vent System Fatigue Analysis (Section A.4.6.2)
26. Torus Attached Piping Analysis r (Section A.4.6.3)
27. Fatigue of Primary Containment Penetrations (Section A.4.6.4)
28. Safety Relief Valve Penetration Fatigue Analysis (Section A.4.6.4.1)

29. Torus Attached Piping Penetrations Fatigue Analyses (Section A.4.6.4.2)
30. Safety Relief Piping Supports Fatigue Analyses (Section A.4.6.5)
31. Main Steam Piping Penetration Bellows Cycle Limits (Section A.4.6.6)
32. Electromatic Relief Valve Bellows Cycle Limits (Section A.4.6.7)
33. Spent Fuel Pool Liner Fatigue Analysis (Section 4.6.8)
34. Spent Fuel Pool Storage Rack Fatigue Analysis (Section A.4.6.9)
35. Other Plant-Specific Time-Limited Aging Analyses (Section A.4.7)
36. Reactor Vessel and Reactor Vessel Head Flaw Evaluations (Section A.4.7.1)
37. Reactor Vessel Flaw Evaluations (Section A.4.7.1.1)
38. Reactor Vessel Closure Head Flaw Evaluations (Section A.4.7.1.2)
39. Reactor Water Cleanup System Weld Overlay Fatigue Flaw Growth Evaluations (Section A.4.7.2)
40. Generic Letter 81-11, "Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking"" (Section A.4.7.3)
41. Valve Fatigue Analyses (Section A.4.7.4)
42. Feedwater Isolation Check Valves Fatigue Analysis (Section A.4.7.4.1)
43. Emergency Condenser Steam Isolation Valves Fatigue Analysis (Section A.4.7.4.2)
44. Emergency Condenser Condensate Return Check Valves Fatigue Analysis (Section A.4.7.4.3)
45. Electromatic Relief Valve Vacuum Breaker Valve Fatigue Analysis (Section A.4.7.5)
46. Core Spray System Weld Fatigue Flaw Growth Evaluation (Section A.4.7.6)
47. Control Rod Drive Bottom Head Penetrations Fracture Mechanics Analysis (Section A.4.7.7)
48. Crane Cyclic Loading Analyses (Section A.4.7.8)
49. Core Shroud Tie Rod X-750 Inconel Component Service Life (Section A.4.7.9)

A.1.5 Quality Assurance Program and Administrative Controls

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to Aging Management Review (AMR). In many cases, existing activities were found adequate for managing aging effects during the subsequent period of extended operation.

A.1.6 Operating Experience

Operating experience from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the quality assurance program, which meets the requirements of 10 CFR Part 50, Appendix B, and the operating experience 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 operating experience program interfaces with and relies on active participation in the Institute of Nuclear Power Operations’ operating experience program, as endorsed by the NRC. The Constellation fleet operating experience program that is implemented at Nine Mile Point Nuclear Station is consistent with the expectations outlined in NUREG-2192, Appendix A.4, “Operating Experience for Aging Management Programs.” In accordance with this program, all incoming operating experience items are screened to determine whether they may involve age-related degradation or aging management impacts. Items so identified are further evaluated and the AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed. Training on age-related degradation and aging management is provided, commensurate with their role in the process, to those personnel responsible for implementing the AMPs and who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. Plant-specific operating experience associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the operating experience program.

A.2.0 Aging Management Programs

A.2.1 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 programs credited for managing the effects of aging.

A.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing condition monitoring program that consists of periodic volumetric, surface, and visual examinations of ASME Class 1, 2, and 3 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 examinations are implemented in accordance with 10 CFR 50.55a and ASME Code, Section XI Subsections IWB, IWC, and IWD.

The program includes augmented inservice inspection requirements for periodic examination of the reactor vessel feedwater and control rod drive return line (CRDRL) nozzles in accordance with the NRC-approved recommendations provided within BWR Owners Group (BWROG) Licensing Topical Report, "Alternate BWR Feedwater Nozzle Inspection Requirements," GE-NE-523-A71-0594-A, Revision 1, May 2000.

These activities include examinations, evaluations, monitoring, and trending of results to confirm that effects of cracking, loss of fracture toughness, and loss of material for components exposed to a reactor coolant, treated water, steam, and air-indoor uncontrolled environments are managed effectively during the subsequent period of extended operation. In addition, although not required by ASME Section XI, visual inspection and leakage testing of the emergency condenser tubes and tube sheets will be implemented through this program for subsequent license renewal.

A.2.1.2 Water Chemistry

The Water Chemistry aging management program is an existing program whose activities mitigate the loss of material due to corrosion; cracking due to stress corrosion cracking (SCC) and related mechanisms; and reduction of heat transfer due to fouling in components exposed to a reactor coolant, steam, or treated water environments. The program includes periodic monitoring of the treated water and control of parameters such as conductivity, chloride, and sulfate concentrations within the guidelines of BWRVIP-190, Revision 2 (EPRI TR-3002025550), "BWR Vessel and Internal Project, BWR Water Chemistry Guideline," in order to minimize aging effects.

The Water Chemistry aging management program manages the treated water contained within the emergency condensers with additional monitoring for conductivity and radioactivity of emergency condenser shell side water.

The Water Chemistry aging management program also monitors and controls the chemical environment of the stator cooling water system such that aging effects of system components are minimized in accordance with EPRI TR-3002000420, "Turbine Generator Auxiliary System Maintenance Guide Volume 4: Generator Stator Cooling Water System," and GEK 45942, "Stator Winding Cooling Water System Operation and Flushing (Constant Flow)," guidelines.

A.2.1.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting aging management program is an existing condition monitoring and preventive program that manages reactor head closure studs, flange threads, and associated nuts, washers, and bushings, for cracking and loss of material. The program is implemented through station procedures based on the examination requirements specified in ASME Code, Section XI, Subsection IWB, Table IWB-2500-1 and preventive measures to mitigate cracking as delineated in NRC Regulatory Guide 1.65, Revision 1, "Materials and Inspections for Reactor

Vessel Closure Studs." The program uses bolting materials for closure studs with actual measured ultimate tensile strengths not exceeding 170 ksi.

A.2.1.4 BWR Vessel ID Attachment Welds

The BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that manages cracking of the reactor vessel interior attachment welds. The program relies on visual examinations to detect cracking. The examination scope, frequencies, and methods are in accordance with BWRVIP-48-A (EPRI 2004-TN8359), "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," dated November 2004. The scope of examinations is expanded when flaws are detected.

Any indications are evaluated in accordance with ASME Code, Section XI, or the guidance in BWRVIP-48-A (EPRI 2004-TN8359). Crack growth evaluations follow the guidance in BWRVIP-14-A (EPRI 2008-TN8301), "Evaluation of Crack Growth in BWR Stainless Steel RPV Internals," dated September 2008; BWRVIP-59-A (EPRI 2007-TN8312), "Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals," dated May 2007; or BWRVIP-60-A (EPRI 2003-TN8313), "Evaluation of Stress Corrosion Crack Growth in Low Alloy Steel Vessel Materials in the BWR Environment," dated June 2003; as appropriate. The acceptance criteria are in BWRVIP-48-A (EPRI 2004-TN8359) and ASME Code, Section XI, Subarticle IWB-3520. Repair and replacement activities are conducted in accordance with BWRVIP-52-A (EPRI 2005-TN8311), "Shroud Support and Vessel Bracket Repair Design Criteria," dated September 2005.

A.2.1.5 BWR Stress Corrosion Cracking

The BWR Stress Corrosion Cracking aging management program is an existing condition monitoring and mitigative program that manages cracking due to intergranular stress corrosion cracking (IGSCC) for all BWR piping and piping welds made of austenitic stainless steel and nickel alloy that are four inches or larger in nominal diameter containing reactor coolant at a temperature above 93 degrees C (200 degrees F) during power operation, regardless of code classification.

The program performs volumetric examinations to detect and manage IGSCC in accordance with NRC Generic Letter (GL) 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping." Modifications to the extent and schedule of inspection in NRC GL 88-01 are allowed in accordance with the inspection guidance in NRC-approved BWRVIP-75-A (EPRI 2005-TN8362), "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules." This program relies on the NRC approved positions that are described in NUREG-0313, Revision 2, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," and NRC GL 88-01 and its Supplement 1 regarding selection of IGSCC-resistant materials, solution heat treatment and stress improvement processes, water chemistry, weld overlay reinforcement, partial replacement, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.

A.2.1.6 BWR Penetrations

The BWR Penetrations aging management program is an existing condition monitoring program that manages the aging effect of cracking due to cyclic loading, intergranular stress corrosion cracking, or stress corrosion cracking of the BWR instrumentation penetrations, control rod drive (CRD) housing and incore-monitoring housing (ICMH) penetrations, and the standby liquid control (SLC)/core plate differential pressure (ΔP) penetration exposed to a reactor coolant environment by performing inspections and flaw evaluations. In addition to the requirements of ASME Code, Section XI, Subsection IWB, the BWR Penetrations program incorporates the inspection and flaw evaluation recommendations of BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines," and the recommendations for reactor water chemistry as described in the Water Chemistry (B.2.1.2) program. The examination categories include volumetric, surface, and visual examination methods.

A.2.1.7 BWR Vessel Internals

The BWR Vessel Internals aging management program is an existing condition monitoring and mitigative program that includes inspections and flaw evaluations in conformance with the guidelines of applicable NRC-approved Boiling Water Reactor Vessels and Internals Project (BWRVIP) documents, and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of X-750 and nickel alloy, stainless steel including martensitic stainless steel (not used in NMP1 reactor vessel internals), cast stainless steel (CASS), and associated welds.

The program manages the effects of cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or irradiation assisted stress corrosion cracking (IASCC), cracking due to cyclic loading (including flow-induced vibration), loss of material, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation.

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable NRC-approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB-2500-1. For example, cracking and loss of material due to wear in the steam dryer are managed by performing visual inspections in accordance with applicable NRC-approved BWRVIP documents. The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components. This program also manages loss of preload by performing visual inspections or stress analyses for adequate structural integrity. In accordance with BWRVIP-315-A, "Reactor Internals Aging Management Evaluation for Extended Operations," Section 4.5.1 Limitation 2, a future version of BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," that addresses extended operations will be implemented as applicable.

Evaluations of reactor vessel internal components determined that supplemental inspections in addition to the existing BWRVIP examination guidelines are not necessary during the subsequent period of extended operation to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement, as well as cracking due to IASCC. This determination is based on neutron fluence, cracking susceptibility, fracture toughness, and consequences of cracking or failure of the reactor vessel internal components. If evaluations determine that supplemental inspections are necessary for certain components, the program conducts the supplemental inspections for adequate aging management.

The BWR Vessel Internals aging management program will be enhanced to:

1. Develop a justification for operation of the top guide through the subsequent period of extended operation by means of a flaw evaluation, consistent with BWRVIP-94, Revision 4; BWRVIP-183-A; BWRVIP-100, Revision 2-A; BWRVIP-14-A; and EPRI Letter 2025-057; as applicable, and develop the necessary inspections and inspection frequencies to validate that the top guide can perform its intended function through the subsequent period of extended operation. Revise procedures governing the top guide inspections to reflect the flaw evaluation, necessary inspections, and inspection frequencies.
2. Develop a justification for the service life of the core shroud tie-rod X-750 subcomponents through the subsequent period of extended operation, consistent with BWRVIP-94, Revision 4, which may include supplemental inspections, inspection frequencies, and technical evaluations to validate that the core shroud tie-rod X-750 subcomponents can perform their intended function through the subsequent period of extended operation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide reasonable assurance that the intended functions of the reactor coolant pressure boundary CASS components (i.e., piping components, pump casings, and covers) with the potential for significant thermal aging embrittlement will be maintained.

The program will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, nickel content, and percent ferrite. Screening is not required for ASME Code Class 1 CASS valve bodies for significance of thermal aging embrittlement because the existing ASME Code, Section XI inspection requirements are adequate for managing the aging effects of Class 1 valve bodies. Components with the potential for significant thermal aging embrittlement will be managed through either qualified inspections, such as enhanced visual examination (EVT-1) or qualified ultrasonic testing methodology, or a component-specific flaw tolerance evaluation.

Reactor vessel internal components fabricated from CASS are not within the scope of this aging management program and are managed by the BWR Vessel Internals (A.2.1.7) aging management program.

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.9 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion aging management program is an existing condition monitoring program that manages wall thinning caused by flow accelerated corrosion (FAC). The program is based on commitments made in response to NRC Generic Letter 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning," and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R4 for an effective FAC program.

CHECWORKS™ is used to predict component wear rates and remaining service life in the systems susceptible to FAC which provides reasonable assurance that structural integrity will be maintained between inspections. The model is revised if any changes in operating conditions or other factors that affect FAC (e.g., plant chemistry, power uprate) have occurred since the CHECWORKS™ model was last updated. Changes may also result from plant modifications that effect FAC behavior such as material changes, the addition of piping systems, piping system configuration changes, and the addition or replacement of in-line components. The CHECWORKS™ model is also refined by importing actual volumetric inspection data thickness measurements and re-running wear rate analyses. This improves the predictive capability of the model to ensure that intended functions are maintained.

The program also manages wall thinning caused by mechanisms other than FAC such as cavitation, flashing, liquid droplet impingement and solid particle erosion in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.

The program includes: (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analysis of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data against acceptance criteria to determine the need for corrective actions including inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

The Flow-Accelerated Corrosion aging management program will be enhanced to:

1. Reassess infrequently used piping systems excluded from the scope of the program to ensure adequate bases exist to justify this exclusion for periods of extended operation beyond 60 years.
2. Reassess piping systems that were susceptible to cavitation but had lines excluded from the erosion program based on the 2 percent exclusion criterion to determine if the lines should be included in the erosion program based on the less than 100 hours of operation per year criteria.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.10 Bolting Integrity

The Bolting Integrity aging management program is an existing condition monitoring program. The program manages aging for loss of preload, cracking, and loss of material of safety-related and nonsafety-related closure bolting on pressure-retaining components. The program utilizes recommendations and guidelines delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," TR-1015336, "Nuclear Maintenance Applications Center: Bolted Joint Fundamentals," and TR-1015337, "Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints," for material selection, use of approved lubricants, proper torquing, and leakage evaluations which are implemented during plant surveillance and maintenance activities.

The program includes periodic visual inspections of closure bolting on pressure-retaining components for indication of loss of preload, cracking, and loss of material as evidenced by pressure-retaining joint leakage. In addition, the program manages aging of submerged mechanical bolting for the traveling screens. Closure bolting on pressure-retaining components and mechanical bolting that are submerged or closure bolting on pressure-retaining components located in piping systems that contain air or gas is inspected by alternative means, such as by sample based periodic inspections. The program also includes preventive measures provided in the EPRI guidance documents to preclude or minimize loss of preload and cracking.

No high-strength closure bolting greater than 2 inches in diameter is in scope of this program. Therefore, sampling based volumetric examinations of closure bolting to detect indications of cracking is not applicable.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program includes inspection of safety-related closure bolting on pressure-retaining components and supplements this program. Inspection activities for bolting in a buried environment or underground with restricted access are performed in conjunction with buried piping and component inspections performed as part of the Buried and Underground Piping and Tanks (A.2.1.27) program.

The Reactor Head Closure Stud Bolting (A.2.1.3) program manages the aging effects of the bolting components for the reactor vessel closure head. The ASME Section XI, Subsection IWE (A.2.1.29) program; ASME Section XI, Subsection IWF (A.2.1.30) program; Structures Monitoring (A.2.1.33) program; Inspection of Water-Control Structures Associated with Nuclear Power Plants (A.2.1.34) program; and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (A.2.1.13) program manage the aging effects of safety-related and nonsafety-related structural bolting. The External Surfaces Monitoring of Mechanical Components (A.2.1.23) program manages the aging effects of safety-related and nonsafety-related bolting associated with ductwork for heating, ventilation, and air conditioning systems.

The Bolting Integrity aging management program will be enhanced to:

1. Perform periodic visual inspections of a representative sample of bolting for bolted joints where leakage is difficult to detect. A representative sample will consist of 20 percent of the population or up to a maximum of 25 bolts and nuts for each material and environment population, whichever is less, and inspections will be performed during each 10-year period of the subsequent period of extended operation. Inspections will be performed of bolting utilized in joints that are submerged, in systems that are not normally pressurized, and in systems containing air or gas. If the minimum sample size is not achieved during a 10-year period, then alternative inspections may be performed. For submerged bolting exposed to treated or raw water, alternative inspections may include (1) diver inspections or (2) remote video inspections. For systems not normally pressurized, alternative inspections may include (1) visual inspection during system tests when the system is pressurized or (2) visual inspection for signs of leakage from when the system was under testing. For systems containing air/gas, alternative inspections may include (1) visual inspection for discoloration when leakage from inside the piping system would discolor the external surfaces of the component; (2) monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary; (3) soap bubble testing on the external mating surface of the bolted component; or (4) thermography, when the temperature of the process fluid is higher than ambient conditions around the component. These inspections will verify that no age-related degradation such as cracking, loss of material, or loss of preload are occurring.
2. Revise procedures governing the direct visual examination of bolted joints to include inspection parameters such as lighting, distance, and offset. Cameras and video equipment may be used to supplement these inspections.
3. Revise engineering procedures to require results of sampling-based inspections to 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.
4. Ensure no fewer than two additional inspections for each sample-based inspection that does not meet acceptance criteria, or 10 percent of the total bolt population of each applicable material, environment, and aging effect combination, whichever is less. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be performed to determine the further extent of inspections. These additional inspections will be completed within the inspection interval in which the original sample-based inspections are conducted.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.11 Open-Cycle Cooling Water System

The Open-Cycle Cooling Water System aging management program is an existing preventive, mitigative, condition monitoring, and performance monitoring program based on the implementation of NRC Generic Letter (GL) 89-13, "Service Water

System Problems Affecting Safety-Related Equipment,” and includes nonsafety-related portions of the open cycle cooling water system. The program includes: (a) surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of heat exchangers, and (c) periodic inspection and maintenance so that corrosion, erosion, cracking, fouling, and biofouling that results in the reduction of heat transfer cannot degrade the performance of systems serviced by the open cycle cooling water system. This program includes guidance beyond the requirements contained in NRC GL 89-13, such as inputs from industry reports and documents (e.g., EPRI documents) that address operating experience such that aging effects are adequately managed.

The Open-Cycle Cooling Water System aging management program will be enhanced to:

1. Perform a minimum of 10 inspections for recurring internal corrosion in the raw water systems, including water-based fire systems, every 24 months until the rate of recurring internal corrosion occurrence no longer meets the criteria for recurring internal corrosion as defined in SLRA Section 3.3.2.2.7. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include: (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of re-inspection interval.
2. Revise the raw water piping inspection program to require that any internal visual inspections performed on in scope concrete piping for subsequent license renewal, parameters monitored or inspected, acceptance criteria and qualifications of inspectors be in accordance with ACI 349.3R and ACI 201.R1.
3. Perform cleaning, flushing and inspections on the cooling coils for two of the reactor building area coolers and two of the turbine building area coolers during each 10-year period. Coils are to be internally cleaned, flushed, then inspected. Inspection method to be capable of detecting wall thinning or loss of material on the internal raw water side of the tubes.
4. Perform quarterly monitoring of the service water and containment spray raw water pump motor bearing temperatures. The results will be trended to establish a baseline, and indications of abnormal temperature trends will be investigated in accordance with the corrective action program.
5. Perform cleaning, flushing and inspection of the service water and containment spray raw water pump motor cooling tubes during maintenance on the motors on a frequency not to exceed 10 years.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.12 Closed Treated Water Systems

The Closed Treated Water Systems program is an existing mitigative program that manages loss of material, cracking, and reduction of heat transfer in piping, piping

components, pump casings, strainers, hoses, valve bodies, tanks, and heat exchanger components exposed to a closed cycle cooling 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: (1) water treatment for nitrite-based chemistries, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion are minimized; (2) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (3) inspections to determine the presence or extent of degradation. The program implements applicable guidance contained in EPRI 3002000590, "Closed Cooling Water Chemistry Guideline," and includes microbiological testing.

The Closed Treated Water Systems aging management program will be enhanced to:

1. Perform condition monitoring including sample-based periodic inspections using techniques (visual, surface, or volumetric) capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects in each 10-year period during the subsequent period of extended operation. If degradation is identified, then the rate of degradation will be projected until the next scheduled inspection. Additional sample-based inspections will be performed if unacceptable aging is identified. If those inspections identify unacceptable aging, then the corrective action program will be used to determine the extent of condition and extent of cause to determine the extent of further inspections.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.13 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 aging management program is an existing condition monitoring program that manages the aging effects of loss of material, cracking, deformation, and indications of loss of preload for load handling bridges, structural members, structural components, and bolted connections. Procedures and controls implement the guidance on the control of overhead heavy load cranes specified in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" and ASME B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top running Trolley Hoist)." The program utilizes periodic visual inspections as described in the ASME B30 series of standards for inspection, detection of aging effects, evaluation, and repair of aging degradation. Monitoring and maintenance of structural components of crane handling systems comply with the maintenance rule requirements provided in 10 CFR 50.65.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be enhanced to:

1. Provide additional procedural guidance to include inspection of bolting for cracking and loss of material.

This enhancement will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.14 Compressed Air Monitoring

The Compressed Air Monitoring aging management program is an existing condition monitoring program that consists of monitoring moisture content and corrosion, and performance of the compressed air system, including (a) preventive monitoring of water (moisture), and other contaminants to keep within the specified limits and (b) inspection of components for indications of loss of material due to corrosion.

This program is based on the NMP1 response to NRC Generic Letter (GL) 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," and INPO's SOER 88-01, "Instrument Air System Failures." It also relies on the guidance from the ASME operations and maintenance standards and guides ASME OM-S/G-1998, Part 17, "Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants," and ANSI/ISA-S7.3-1975, "Quality Standard for Instrument Air," and EPRI TR-108147, "Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079," for testing and monitoring air quality and moisture. Program activities include air quality checks at various locations to ensure the dew point, particulates, and hydrocarbons are maintained within specified limits, and inspections of the internal surfaces of compressed air system components for signs of loss of material due to corrosion.

The Compressed Air Monitoring aging management program will be enhanced to:

1. Revise program implementation and criteria to be in accordance with ANSI/ISA-7.0.01-1996 guidelines. The existing program is based on ANSI/ISA-7.3.1975 guidelines, and the enhancement will bring the existing program in line with current standards and vendor recommendations without any impact on the program's ability to maintain component intended functions during the subsequent period of extended operation.
2. Revise program implementation and criteria to be in accordance with ASME OM-2012 Division 2, Part 28 guidelines. The existing program is based on ASME OM-1998, Part 17 guidelines, and the enhancement will bring the existing program in line with current standards and vendor recommendations without any impact on the program's ability to maintain component intended functions during the subsequent period of extended operation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.15 Fire Protection

The Fire Protection aging management program is an existing condition monitoring program that includes fire barrier visual inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors, fire dampers, and other materials that perform a fire barrier function. Periodic visual inspection and functional testing of the fire rated doors is performed to ensure that their functionality is maintained and aging effects managed. The program also includes visual inspections and periodic functional tests

of the low-pressure carbon dioxide and halon fire suppression systems using the National Fire Protection Association Codes and Standards for guidance.

The Fire Protection aging management program will be enhanced to:

1. Perform visual inspections of combustible liquid spill retaining curbs.
Combustible liquid spill retaining curbs will be inspected for signs of age-related degradation that could affect the intended function of the component. Curbs will be inspected for signs of cracking, spalling, corrosion, or loss of material that could impede the leak tight functionality of the curb.
2. Perform visual inspections of fire doors for age-related degradation.
3. Visually inspect fire damper housings for cracking.
4. Perform an inspection of not less than 10 percent of each type of seal during each inspection interval.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.16 Fire Water System

The Fire Water System aging management program is an existing condition monitoring, performance monitoring, and preventive program that manages loss of material and flow blockage due to fouling. The program manages these aging effects by monitoring system pressure, flushing the system fire header, flow testing the fire main, performance testing the fire pumps, full flow flushing and flow verification of the fire hydrants, flushing and flow testing sprinkler and deluge systems, and visually inspecting systems using the guidance of NFPA 25, 2011 Edition.

The program applies to water-based fire protection systems that consist of sprinklers, fittings, valves, hydrants, hose stations, standpipes, strainers, pumps, and aboveground and buried piping and components. The program manages aging of fire protection system components exposed to raw water, indoor and outdoor air, and condensation environments. Aging of the external surfaces of buried fire main piping is managed as described in the Buried and Underground Piping and Tanks (A.2.1.27) aging management program.

Inspections and tests follow station procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes for an adequate examination.

Testing or replacement of sprinklers that have been in place for 50 years, 60 years, 70 years, and 80 years is performed using the guidance of NFPA 25, 2011 Edition if a station-specific evaluation cannot determine the water is non-corrosive to sprinklers.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

The Fire Water System aging management program will be enhanced to:

1. Perform a one-time volumetric wall thickness inspection test of a representative sample of sections of pipe that are periodically subjected to flow but are normally dry. The representative sample will be based on the population of system piping that is periodically subject to flow but is normally dry. The one-time volumetric wall thickness inspection test activity will include criteria for selection of inspection locations, acceptance criteria, and will specify the need for follow-up examinations based on inspection results.
2. Revise the hydrant flushing procedure to require hydrants be flushed for at least a full minute.
3. Perform system mainline strainer inspections after system operation or testing.
4. Perform, on a five-year frequency, internal visual inspections of every other in scope suppression system. These inspections will include nozzle inspections when performed on deluge systems. The systems not inspected in the first five-year interval will be inspected in the second five-year interval. In dry pipe systems and pre-action systems, the sprinkler removed for inspection shall be from the most remote branch line from the source of water that is not equipped with the inspector's test valve. Tubercles or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC). If the presence of foreign organic and/or inorganic material is found in any system in a building during the five-year internal inspection of piping, all systems shall be assessed. If the presence of sufficient foreign organic and/or inorganic material is found to obstruct pipe or sprinklers, an obstruction investigation will be conducted as described in Section 14.3 of NFPA 25. Alternatively, nondestructive examinations capable of ensuring flow blockage in piping and nozzles will not occur will be performed. The population of suppression systems eligible for inspection consist of the in scope wet pipe sprinkler systems, dry-pipe systems, preaction systems, and deluge systems that are not functionally tested.
5. Perform two additional fire water system flow tests within the test interval (frequency) for each failed test.
6. Perform a system mainline strainer inspection and cleaning after system flow exceeding that of a nominal two-inch orifice.
7. Perform annual functional tests of the: 1) turbine building west wall water curtain, 2) turbine building south wall water curtain, and 3) turbine building south and east control building wall exposure above administration building roof deluge systems.
8. Perform annual inspections of the two charcoal deluge system strainers and the strainer to the interior spray system manifold.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. One-time inspections will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.17 Not Used

A.2.1.18 Fuel Oil Chemistry

The Fuel Oil Chemistry aging management program is an existing mitigative and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The program relies on a combination of surveillance and maintenance procedures. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with ASTM guidelines. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic cleaning and draining of tanks and by verifying the quality of fuel oil. Fuel oil sampling and analysis is performed in accordance with approved procedures for stored fuel oil and new fuel oil before its introduction into the storage tanks.

The Fuel Oil Chemistry aging management program will be enhanced to:

1. Perform periodic internal inspection of the emergency diesel generator fuel oil day tanks and diesel driven fire pump fuel oil day tank at least once during each 10-year period starting 10 years prior to the subsequent period of extended operation. Each tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, then these diesel fuel tanks will be volumetrically inspected.
2. Perform periodic (quarterly) sampling, analysis, and trending for water and sediment content, particulate concentration, and the levels of microbiological organisms for the emergency diesel generator fuel oil day tanks and diesel driven fire pump fuel oil day tank. The new sampling activities will include a sampling methodology that includes a representative sample from a low point in the tank which will provide for a more conservative sample than the multilevel sampling techniques described in ASTM D4057.
3. Perform periodic (quarterly) sampling, analysis, and trending for the levels of microbiological organisms for the emergency diesel generator fuel oil storage tanks and the diesel driven fire pump fuel oil storage tank.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.19 Reactor Vessel Material Surveillance

The Reactor Vessel Surveillance aging management program is an existing condition monitoring program that manages the loss of fracture toughness due to neutron irradiation embrittlement of the reactor vessel beltline materials. Embrittlement evaluations are performed in accordance with Regulatory Guide 1.99, Revision 2, 'Radiation Embrittlement of Reactor Vessel Materials.' The program meets the requirements of 10 CFR 50, Appendix H by providing sufficient material data and dosimetry to monitor irradiation embrittlement through the subsequent period of extended operation and by providing operating restrictions on reactor coolant inlet temperature and neutron exposure (spectrum and flux). The program

monitors plant operating conditions to ensure appropriate steps are taken if reactor vessel exposure conditions are altered, such as the review and updating of 80-year fluence projections to support upper shelf energy calculations and pressure-temperature limit curves. These measures are effective in detecting the extent of embrittlement of the reactor pressure vessel during the subsequent period of extended operation.

The Reactor Vessel Surveillance program is part of the BWRVIP Integrated Surveillance Program (ISP) described in the latest NRC-approved version of BWRVIP-321, Revision 1-A. NMP1 is a BWRVIP ISP non-host plant with one capsule installed. NMP1 is not scheduled for withdrawal of any capsules during the subsequent period of extended operation and relies on capsule test data hosted at Peach Bottom, Unit 3 in the Group 1 capsule. The program is effectively providing fluence and materials data necessary for managing the effects of loss of fracture toughness due to neutron irradiation embrittlement during the period of extended operation. Any changes to the capsule withdrawal schedule will be NRC approved prior to implementation. Untested capsules placed in storage will be maintained for future insertion.

The Reactor Vessel Material Surveillance aging management program will be enhanced to:

1. Implement BWRVIP-321, Revision 1-A to maintain compliance with 10 CFR 50 Appendix H during the subsequent period of extended operation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.20 One-Time Inspection

The One-Time Inspection aging management program is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (1) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation; (2) the insignificance of an aging effect; and (3) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the program will include: (1) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, and (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined.

Periodic inspections instead of this program will be used for structures or components with known age-related degradation mechanisms or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in

accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections will be completed within the 10 years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.21 Selective Leaching

The Selective Leaching aging management program is a new condition monitoring program that will monitor components constructed of materials that are susceptible to selective leaching and that are exposed to environments that may result in the occurrence of selective leaching in susceptible materials. Susceptible materials include gray cast iron, malleable iron, ductile iron, and copper alloys containing greater than 15 percent zinc. Copper alloys containing greater than eight percent aluminum are also susceptible to selective leaching; however, there are no components within the scope of license renewal that are constructed of this material at NMP1. The selective leaching program includes one-time inspections for susceptible components exposed to closed cycle cooling water and treated water environments since plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections are conducted for susceptible components exposed to raw water, waste water, and soil (which may include groundwater) environments.

Inspections are conducted on a representative sample of components in each material and environment population. Inspections consist of visual and mechanical examination techniques (for gray cast iron, malleable iron, and ductile iron components) as well as periodic non-destructive and destructive examinations for determining physical properties (i.e., degree of dealloying, depth of dealloying, through-wall thickness, and chemical composition) for components exposed to raw water, waste water, and soil environments. Volumetric non-destructive examinations will employ techniques that have been demonstrated to be capable of detecting and characterizing selective leaching degradation. The volumetric technique will be qualified equivalent to an Intermediate Rigor level of qualification of ASME Code Section V, "Nondestructive Examination," Article 14, "Examination System Qualification," and the qualification documentation will include the applicability and limitations of the technique including the specific material type susceptible to selective leaching that may be inspected using the specified technique. Two volumetric non-destructive examinations will be performed when the non-destructive examination is credited in lieu of a destructive examination. Inspections and tests will be conducted to determine whether loss of material will affect the ability of the components to perform their intended function through the subsequent period of extended operation. Inspections will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions, as appropriate. 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.

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.22 ASME Code Class 1 Small-Bore Piping

The ASME Code Class 1 Small-Bore Piping aging management program is a new condition monitoring program that will augment the existing ASME Code, Section XI requirements and is applicable to ASME Code Class 1 small-bore piping and systems with a nominal pipe size (NPS) 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. Destructive examination methods may be performed in lieu of volumetric examination. The program examinations are performed to verify that degradation is not occurring and to validate the effectiveness of existing programs and practices, thereby confirming that no additional aging management is required for the subsequent period of extended operation. The extent and schedule for volumetric examination is based on NMP1 plant-specific operating experience which reveals that cracking of a Class 1 small-bore weld has occurred. The program provides for a one-time examination of a sample of the total population of butt welds and periodic inspections of a sample of the total population of socket welds based on NUREG-2191, Chapter XI.M35, "ASME Code Class 1 Small-Bore Piping," Table XI.M35-1, "Examinations." Review of NMP1 operating experience identified no history of age-related ASME Code Class 1 small-bore butt weld failures, and one unmitigated ASME Code Class 1 small-bore piping socket weld failure that occurred in 2006.

In regard to socket welds, NMP1 submitted Licensee Event Report (LER) 2006-001-00, "Technical Specification Required Shutdown due to Increased Drywell Leakage," on August 10, 2006. Investigation of the failure discovered on the 'B' recirculation pump loop drain line found the cause to be due to vibrational fatigue. The failed drain valve and adjacent welds were replaced. There has been no additional cracking or through-wall leak events on the Unit 1 ASME Code Class 1 small-bore piping socket welds. Because this failure was not mitigated via a design change, this program implements a sample size and schedule for periodic inspections every 10 years, with the first inspections to be completed within six years prior to the subsequent period of extended operation for the populations of socket welds in Unit 1 as specified in NUREG-2191, Chapter XI.M35, Table XI.M35-1. Non-destructive and destructive testing will determine whether age-related cracking is occurring in the total population of susceptible ASME Code Class 1 small-bore piping welds.

In regard to butt welds, due to no history of age-related failures, this program implements a sample size and schedule for one-time inspections to be completed within six years prior to the subsequent period of extended operation for the

populations of butt welds in Unit 1 as specified in the NUREG-2191, Chapter XI.M35, Table XI.M35-1.

If one-time inspections identify unacceptable age-related cracking based on evaluation of the flaw performed in accordance with ASME Code, Section XI, IWB-3132, then periodic examinations will be performed on 10 percent of the applicable weld population, up to a maximum of 25 welds per population. If required, periodic examinations will be performed on a 10-year frequency.

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections will be completed within the six years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.23 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that will manage the loss of material, cracking, hardening or loss of strength (of elastomeric and polymeric components), and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic, elastomeric, polymeric, and insulation jacketing (insulation when not jacketed), and cementitious components will be conducted. This program does not manage cracking due to stress corrosion cracking (SCC) of aluminum, stainless steel, or copper alloy components exposed to air or condensation environments; nor does the program manage loss of material of aluminum or stainless steel components exposed to air or condensation environments. The One-Time Inspection program will be used to confirm that these aging effects are not occurring.

For certain materials, such as flexible polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) will be periodically inspected every 10 years during the subsequent period of extended operation. Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria will be clear enough to reasonably assure a singular decision is derived based on observed conditions.

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new condition monitoring program that will manage loss of material, recurring internal corrosion, and cracking of metallic components, as well

as loss of material and hardening or loss of strength in elastomers, and cracking or blistering, loss of material, and hardening or loss of strength in polymers. Reduction of heat transfer and flow blockage will also be managed. This program will consist of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components and other mechanical components. Applicable environments include dry air, condensation, gas, lubricating oil, fuel oil, diesel exhaust, closed cycle cooling water, raw water, treated water and waste water. Visual (VT-1), volumetric, or surface examinations are conducted to detect cracking of stainless steel and copper alloy components with 15 percent zinc or more. Except for aging effects in elastomers and polymers, aging effects associated with components within the scope of the Open Cycle Cooling Water System (A.2.1.11), Closed Treated Water System (A.2.1.12), Compressed Air Monitoring (A.2.1.14), and Fire Water System (A.2.1.16) programs are not managed by this program.

Internal inspections will be performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. Although Nine Mile Point Nuclear Station is a multi-unit site, activities under this program apply only to a single unit (Unit 1). At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population are inspected. Sample selection will consider component susceptibility to aging due to factors such as time in service and severity of operating conditions. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program.

Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures which include inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria will be based upon component, material, and environment combinations and ensure that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Quantitative acceptance criteria are used whenever practical and qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.25 Lubricating Oil Analysis

The Lubricating Oil Analysis aging management program is an existing condition monitoring program that provides monitoring of oil in piping, piping components, gear boxes, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. The program provides reasonable assurance that the oil environment in the mechanical systems is maintained to the required quality, and the oil systems are maintained free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material or

reduction of heat transfer. Program activities include sampling, analysis, and trending of lubricating oil for detrimental contaminants. The presence of water or particulates may also indicate in-leakage and corrosion product buildup.

The Lubricating Oil Analysis aging management program will be enhanced to:

1. Perform periodic sampling and testing of lubricating oil for moisture and corrosion particles in the liquid poison system pump gearboxes, following industry or vendor recommended practices. Alternatively, test old oil after periodic oil changes for the liquid poison system pump gearboxes based on vendor intervals or station experience.
2. Perform periodic sampling and testing of hydraulic oil for moisture and corrosion particles in the circulating water gates and hoists system hydraulic fluid reservoir, following industry or vendor recommended practices. Alternatively, test old oil after periodic oil changes for the circulating water gates and hoists system hydraulic fluid reservoir based on vendor intervals or station experience.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program is an existing condition monitoring program that includes periodic inspection, testing, monitoring, and analysis of test coupons of the neutron-absorbing material in the spent fuel storage racks to ensure that a five percent subcriticality margin in the spent fuel pool is maintained during the subsequent period of extended operation. The program consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearances, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges) and boron areal density as observed from coupons or in-situ techniques to monitor for loss of material, changes in dimension, and loss of neutron-absorption capacity of the material.

A.2.1.27 Buried and Underground Piping and Tanks

The Buried and Underground Piping and Tanks aging management program is an existing condition monitoring program that manages the aging effects associated with the external surfaces of buried and underground piping and tanks including loss of material, cracking, hardening and loss of strength. It addresses piping and tanks constructed of any material, including carbon steel, polymers, copper alloys, fiberglass, asbestos cement, and cast iron.

The program also manages aging through preventive and mitigative actions (i.e., coatings, backfill quality, and cathodic protection). The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. For steel components, the acceptance criteria for the effectiveness of the cathodic protection is -850 mV instant off relative to copper/copper sulfate reference electrode.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation, an increase in the sample size will be conducted.

The Buried and Underground Piping and Tanks aging management program will be enhanced to:

1. Perform one direct visual inspection of a 10-linear foot segment of buried carbon steel piping within the scope of license renewal during each 10-year period beginning 10 years prior to the subsequent period of extended operation. The number of inspections will be increased to six 10-linear foot segments of buried carbon steel piping within the scope of license renewal if either of the following criteria are not met for the cathodic protection system protecting the buried steel piping within the scope of license renewal:
 - a. System is maintained operational at least 85 percent of the time for 10 years prior to the subsequent period of extended operation (excluding time periods in which the cathodic protection system is off-line for testing).
 - b. System has provided effective protection for buried steel piping as verified through acceptable annual system testing results 80 percent of the time for 10 years prior to the subsequent period of extended operation. Testing results for cathodic protection systems protecting steel piping is acceptable if instant off potential is -850 mV or more negative, relative to a copper/copper sulfate reference electrode.
2. Perform extent of condition inspections for steel piping as follows: When measured pipe wall thickness, projected to the end of the subsequent period of extended operation, does not meet the minimum pipe wall thickness requirements due to degradation of the external surface, the number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The scope of the follow-up inspections will be determined based on the analysis. Timing of any additional inspections will be based on the severity of the identified degradation and the consequences of leakage or loss of function. Any additional inspections will be performed within the same 10-year inspection interval in which the original degradation was identified, or within four years after the end of the 10-year interval if the degradation was identified in the latter half of the 10-year interval. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism or if the piping system or portion of the system is replaced or otherwise mitigated within the same 10-year inspection interval in which the original degradation was identified or within four years after the end of the 10-year interval, if the degradation was identified in the latter half of the 10-year interval.
3. Perform annual system monitoring of the cathodic protection system to ensure effective protection of buried piping with a grace period of up to two months. However, in each calendar year, system monitoring is conducted at least once.

4. Perform direct visual inspection of the in scope underground steel pipe and copper components located in the emergency diesel fuel oil valve pit during each 10-year period beginning 10 years prior to the subsequent period of extended operation.
5. Perform direct visual inspection of the in scope underground fiberglass reinforced plastic and carbon steel piping located in the diesel fire pump tank access vault during each 10-year period beginning 10 years prior to the subsequent period of extended operation.
6. Perform monthly monitoring of the fire system leak rate. The results will be trended to establish a baseline and indications of abnormal leak rate or increasing trends will be investigated in accordance with the corrective action program. If unexplained changes to the fire system leak rate are identified, then a flow test will be performed by the end of the next refueling outage.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be performed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation, and no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.28 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 aging management program is a new condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, closed-cycle cooling water, waste water, air, and condensation. For buried cement lined fire water piping, opportunistic inspections will be performed in addition to flow tests and internal piping inspections at intervals specified in NFPA 25 and in accordance with the Fire Water System (A.2.1.16) program. There are no piping or components with internal coatings/linings in the program scope that are exposed to fuel oil, lubricating oil, or treated borated water. This program is not used to manage the integrity of coatings applied to external surfaces of components. This program manages these aging effects for internal coatings by conducting periodic visual inspections of all coatings/linings applied to the internal surfaces of in scope components where loss of coating or lining integrity could impact the component's or downstream component's current licensing basis intended function(s).

For tanks and heat exchangers, all accessible surfaces are inspected. Piping and piping component inspections are sampling-based. For non-cementitious coatings/linings, training and qualification of individuals involved in coating/lining inspections, and the evaluation of inspection results, are conducted in accordance with ANSI and ASTM International Standards endorsed in NRC Regulatory Guide (RG) 1.54, "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 are not acceptable. Blisters are limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the

substrate with blister size or frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable if there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation, and no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.29 ASME Section XI, Subsection IWE

The ASME Section XI, Subsection IWE aging management program is an existing condition monitoring program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure-retaining components of steel containments for signs of degradation, damage, and irregularities. The program also includes visual examinations for distress of the underlying containment metal shell for coated areas. Corrective actions are performed in accordance with ASME Code requirements if unacceptable indications are identified. Acceptability of inaccessible areas of the steel containment shell is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

This program also includes aging management for the potential loss of material due to corrosion in the inaccessible areas of the BWR Mark I steel containment.

The ASME Section XI, Subsection IWE aging management program will be enhanced to:

1. Perform a one-time supplemental surface or enhanced visual examination (i.e., EVT-1 exam) on accessible portions of a representative sample (i.e., 20 percent of population) of high-temperature mechanical drywell penetrations subject to cyclic loading or stress corrosion cracking, to detect cracking. If cracking is identified as a result of these inspections, additional inspections will be conducted to increment the sample size by one additional penetration at a time from the uninspected population until cracking is no longer detected. The corrective action program will be used to determine the extent of further inspections, if necessary.
2. Implement a one-time supplemental volumetric examination of the containment metal shell surfaces that are inaccessible from one side, if triggered by plant-specific operating experience. The trigger for this supplemental examination is plant-specific occurrence or recurrence of containment metal shell corrosion (base metal material loss exceeding 10 percent of nominal plate thickness over a local area as defined by ASME Section III 1965, Section N-513.3) initiated on the inaccessible side or areas, identified since the date of issuance of the first renewed operating license. For the purposes of this enhancement, a local area

is defined as a circular area with a radius defined by one-half of the square root of the product of the containment metal shell diameter times the containment metal shell thickness at the location in question. This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly selected and focused areas most likely to experience degradation based on plant-specific operating experience and/or other relevant considerations such as environment. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically with 95 percent confidence that 95 percent of the accessible portion of the containment metal shell is not experiencing corrosion degradation with greater than 10 percent loss of nominal thickness. If required, the supplemental volumetric examinations will be completed within two refueling outages of identification of the triggering containment metal shell corrosion or sooner, as determined by the corrective action program based on the severity of the identified degradation.

3. Provide guidance for 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 consistent with EPRI NP-5067 and TR-104213. Also, provide guidance for storage, lubricant selection, and bolting and coating material selection consistent with Section 2 of Research Council on Structural Connections (RCSC) publication "Specification for Structural Joints Using High-Strength Bolts."

The program will be enhanced no later than six months prior to the subsequent period of extended operation. The one-time supplemental surface or enhanced visual examination will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation. If required, the one-time supplemental volumetric examination will be performed in accordance with the schedule identified in the enhancement.

A.2.1.30 ASME Section XI, Subsection IWF

The ASME Section XI, Subsection IWF aging management program is an existing condition monitoring program that consists of visual examinations of ASME Class 1, 2, 3, and MC piping and component supports and structural bolting for signs of degradation (i.e., loss of material, loss of mechanical function, cracking, pitting crevice corrosion, overload, wear, dirt and debris accumulation, and loss of preload in air-indoor uncontrolled, air-outdoor, or treated water environments), evaluations, and corrective actions. The program also manages reduction of fracture toughness of reactor vessel support components. The program is implemented through procedures, in accordance with the requirements of the ASME Code, Section XI, Subsection IWF, as approved in 10 CFR 50.55a. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation.

This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. The program will be enhanced to implement additional inspections beyond the inspections

required by the 10 CFR 50.55a ASME Code Section XI, Subsection IWF program. This consists of a one-time inspection of an additional five percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection will be conducted within the five years prior to entering the subsequent period of extended operation. If high-strength bolting in sizes greater than 1-inch nominal diameter are installed, 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.

The program will be enhanced to address sampling requirements for elective repairs. 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.

The ASME Section XI, Subsection IWF aging management program will be enhanced to:

1. Perform periodic evaluations of the acceptability of inaccessible areas of supports (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe), when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas of supports. Perform these evaluations once every 10 years during the subsequent period of extended operation.
2. Perform a one-time inspection of an additional five percent of the currently inspected sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. The one-time inspection will be conducted within five years prior to entering the subsequent period of extended operation. The additional supports will be selected from the remaining population of IWF piping supports not already included in the current inspection sample. The expanded sample locations will be selected to include components that are more susceptible to age-related degradation (i.e., based on factors such as time in service, material, and aggressiveness of the environment) than those not in the sample.
3. Revise procedures to require volumetric examination of high-strength bolting (actual measured yield strength greater than or equal to 150 ksi) in sizes greater than 1-inch nominal diameter (including ASTM A490 and equivalent ASTM F2280), if additional high-strength bolting is installed. The examination shall be comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 and performed at least once per 10-year interval to detect cracking, in addition to the VT-3 examination required by ASME Section XI.
4. Provide guidance, regarding the selection of supports to be examined in subsequent inspection intervals, when a support that is acceptable for continued service as defined in IWF-3400, is restored in accordance with the corrective action program. The enhanced guidance will ensure that future inspection populations are increased or modified to include another support, of the same type and function, that has not been restored to correct the observed condition. The purpose of increasing or modifying the sample size is to assure that the support population continues to be representative of the remaining population of supports that were not corrected.

5. Perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of a 20 percent representative sample of high-strength bolts (defined as bolts with the same material and environment combination), on a 10-year frequency during the subsequent period of extended operation. The sample shall include the bolting that is most susceptible to age-related degradation (i.e., based on time in service, aggressive environment). If the volumetric examination of these bolts reveals conditions that do not meet acceptance criteria, then the results will be entered into the corrective action program and the inspection will be expanded to include additional high-strength bolts.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. One-time inspections will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.31 10 CFR Part 50, Appendix J

The 10 CFR Part 50, Appendix J aging management program is an existing performance monitoring program that consists of monitoring and determining leakage rates through the containment system as a whole including the shell, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. This program complies with Option B requirements of 10 CFR Appendix J with plant-specific exceptions approved by the NRC as part of license amendments, and implements the guidelines provided in 10 CFR 50, Appendix J Option B; Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program;" NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J;" ANSI/ANS 56.8, "Containment System Leakage Testing Requirements;" and Bechtel Topical Report BN-TOP-1, "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants."

A.2.1.32 Masonry Walls

The Masonry Walls aging management program is an existing condition monitoring program implemented as part of the Structures Monitoring program (A.2.1.33). The program is based on guidance provided in NRC IE Bulletin 80-11, "Masonry Wall Design," and NRC Information Notice 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," and is implemented through station procedures.

The Masonry Walls program addresses loss of material, loss of bond, and cracking due to age-related degradation (e.g., shrinkage, creep, aggressive environment) of concrete masonry walls and inspects for separation, along with gaps between the support and masonry walls such that the evaluation basis is not invalidated and intended functions are maintained. The program relies on periodic visual inspections on an interval not to exceed five years to monitor, trend, and maintain the condition of masonry walls within the scope of license renewal. Masonry walls that are considered fire barriers are also managed by the Fire Protection (A.2.1.15) program.

The Masonry Walls aging management program will be enhanced to:

1. Perform masonry wall periodic inspections on a frequency not to exceed five years except for the normally inaccessible areas due to high radiation.

This program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.33 Structures Monitoring

The Structures Monitoring aging management program is an existing condition monitoring program that consists of periodic visual inspection and monitoring of the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those describe in ACI 349.3R, ACI 201.1R, and SEI/ASCE 11) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Inspections also include 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 the degradation. The acceptance criteria are derived from applicable consensus codes and standards.

The Structures Monitoring aging management program will be enhanced to:

1. Include the following structures within the scope of the program:
 - a. Administration building (Original)
 - b. Administration building extension
 - c. Emergency diesel generator fuel oil storage tank foundation
 - d. Emergency diesel generator fuel oil transfer valve pit
 - e. Ring girder for the reactor vessel support skirt
2. Include the following components and commodities within the scope of the program:
 - a. Manholes
 - b. Seismic joint filler
 - c. Sliding surfaces
 - d. Trash racks
3. Implement preventive actions to emphasize proper selection of bolting material and lubricants and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high strength bolting. For ASTM A325 or ASTM A490 bolts, the preventive actions for storage, lubricant selection,

and bolting and coating material selection will be in accordance with Section 2 of Research Council for Structural Connection publication “Specification for Structural Joints Using High-Strength Bolts.”

4. Clarify procedures to state that evidence of cracking, spalling, scaling, discoloration, and leaching could indicate the presence of increased porosity and permeability due to mechanisms of aggressive chemical attack or leaching of calcium hydroxide and carbonation.
5. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion and for accumulation of debris or dirt. Establish acceptance criteria for sliding surfaces as no significant loss of material due to wear or corrosion and no debris or dirt that could restrict or prevent sliding of the surfaces, as required by design.
6. Expand the program to monitor elastomeric structural sealants, seismic joint fillers, and vibration isolators for cracking, loss of material, and hardening. Supplement visual inspection of elastomeric elements with tactile inspection to detect hardening if the intended function is suspect. Establish acceptance criteria for elastomeric structural sealants, seismic joint fillers, and vibration isolation elements as no loss of material, cracking, or hardening that can lead to loss of intended function.
7. Develop a new implementing procedure or revise an existing implementing procedure to address aging management of inaccessible areas exposed to potentially aggressive groundwater/soil environment that will include the following:
 - a. Monitor raw water and ground water chemistry for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from locations that are representative of the groundwater in contact with structures within the scope of subsequent license renewal.
 - b. Develop engineering evaluations to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or increased frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil.
 - c. Develop the initial engineering evaluations prior to the subsequent period of extended operation. Develop follow-up engineering evaluations on an interval not to exceed five years.
 - d. If warranted based on the engineering evaluations, perform focused inspections of representative, accessible (leading indicator) structural elements, or if accessible areas will not be leading indicators for the potential

aging mechanisms, excavate and inspect buried concrete elements exposed to potentially aggressive groundwater/soil.

- e. If degraded concrete is identified, as part of the focused inspections of leading indicators (representative, accessible or exposed inaccessible concrete), enter adverse results that exceed ACI 349.3R-02 tier 2 criteria into the corrective action program, and expose inaccessible concrete so that the extent of the condition can be determined, baseline conditions documented, and additional actions identified such as repairs, new preventive actions, additional evaluations, and future inspections.
8. Monitor and trend indications of groundwater infiltration or through-concrete leakage. If leakage volumes allow, procedures will be revised to clarify that water chemistry analysis should be considered for parameters including pH, as well as mineral, chloride, sulfate and iron content in the water to assess for potential impact on age-related degradation of concrete or steel reinforcement. This assessment may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels.
9. Perform structures monitoring periodic inspections on a frequency not to exceed five years except for the normally inaccessible areas due to high radiation.
10. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R-02 with respect to knowledge of inservice inspection of concrete and visual acuity requirements.
11. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
12. Provide additional guidance on visual indications such as exudations, surface staining, expansion causing structural deformation, relative movement or displacement, misalignment or distortion of attached components for detection of expansion due to alkali-aggregate reactivity in concrete.
13. Quantitative baseline inspection data will be established against acceptance criteria provided in the enhanced Structures Monitoring program prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria are acceptable in lieu of performing a new baseline inspection.
14. Provide evaluation criteria for structural concrete by using quantitative second tier criteria in Chapter 5 of ACI 349.3R-02.
15. Clarify that loose bolts and nuts are not acceptable unless accepted by engineering evaluations.

The program will be enhanced, and the initial engineering evaluation will be completed no later than six months prior to the subsequent period of extended operation. Baseline inspections will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.34 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 that consists of the inspection and surveillance of raw-water control structures associated with emergency cooling systems or flood protection. The program also includes structural steel and structural bolting associated with water-control structures. In general, parameters monitored are in accordance with Section C.2 of NRC Regulatory Guide (RG) 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," and quantitative measurements should be recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Inspections should occur at least once every five years with the exception of the intake and discharge tunnels which will be inspected at least once every three refueling outages. Structures exposed to aggressive water require additional plant-specific investigation.

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be enhanced to:

1. Add the following structures to the scope of the program:
 - a. Unit 1 Rock Dike
 - b. Unit 2 Revetment-Ditch System (260 ft which replaced Unit 1 Rock Dike)
2. Explicitly include the following components within the scope of the program:
 - a. Trash racks
 - b. Sluice gates
3. Implement preventive actions to emphasize proper selection of bolting materials and lubricants and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For ASTM A325 and ASTM A490 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection will be in accordance with Section 2 of Research Council for Structural Connection publication "Specification for Structural Joints Using High-Strength Bolts."
4. Perform periodic inspections of water-control structures on an interval not to exceed five years except for the intake tunnel and discharge tunnel.
5. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R-02 with respect to knowledge of inservice inspection of concrete and visual acuity requirements.
6. Develop a new implementing procedure or revise an existing implementing procedure to address aging management of inaccessible areas exposed to potentially aggressive groundwater/soil environment that will include the following:

- a. Monitor raw water and ground water chemistry for pH, chlorides, and sulfates on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year) from locations that are representative of the groundwater in contact with structures within the scope of subsequent license renewal.
 - b. Develop engineering evaluations to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or increased frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil.
 - c. Develop the initial engineering evaluations prior to the subsequent period of extended operation. Develop follow-up engineering evaluations on an interval not to exceed five years.
 - d. If warranted based on the engineering evaluations, perform focused inspections of representative, accessible (leading indicator) structural elements, or if accessible areas will not be leading indicators for the potential aging mechanisms, excavate and inspect buried concrete elements exposed to potentially aggressive groundwater/soil.
 - e. If degraded concrete is identified, as part of the focused inspections of leading indicators (representative, accessible or exposed inaccessible concrete), enter adverse results that exceed ACI 349.3R-02 tier 2 criteria into the corrective action program, and expose inaccessible concrete so that the extent of the condition can be determined, baseline conditions documented, and additional actions identified such as repairs, new preventive actions, additional evaluations, and future inspections.
7. Quantitative baseline inspection data will be established against acceptance criteria provided in the enhanced Inspection of Water-Control Structures Associated with Nuclear Power Plants program prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria are acceptable in lieu of performing a new baseline inspection.
 8. Monitor and trend indications of groundwater infiltration or through-concrete leakage. If leakage volumes allow, procedures will be revised to clarify that water chemistry analysis should be considered for parameters including pH, as well as mineral, chloride, sulfate and iron content in the water to assess for potential impact on age-related degradation of concrete or steel reinforcement. This assessment may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels.

9. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
10. Provide evaluation criteria for structural concrete using quantitative second tier criteria in Chapter 5 of ACI 349.3R-02.
11. Clarify that loose bolts and nuts are not acceptable unless accepted by engineering evaluations.

The program will be enhanced and the initial engineering evaluation will be completed no later than six months prior to the subsequent period of extended operation. Baseline inspections will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.35 Protective Coating Monitoring and Maintenance

The Protective Coating Monitoring and Maintenance program is an existing condition monitoring program implemented in accordance with Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." The program consists of guidance for selection, application, inspection and maintenance of protective coatings. Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel liner, steel drywell shell, structural steel, supports, penetrations, and concrete walls and floors) aids in decontamination and serves to prevent or minimize loss of material due to corrosion of carbon steel components, but these coatings are not credited for managing the effects of corrosion for the carbon steel drywell shell and components. Degraded coatings in containment are assessed periodically to ensure post-accident operability of the emergency core cooling system.

The Protective Coating Monitoring and Maintenance aging management program will be enhanced to:

1. Require personnel qualifications meet the requirements discussed in ASTM D 5163-08, paragraph 9.

This program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.36 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 aging management program is an existing condition monitoring program that manages the effects of reduced insulation resistance of accessible electrical cable and connection insulation within the scope of license renewal subjected to an adverse localized environment.

Accessible in-scope electrical cable and connection electrical insulation material is visually inspected for cable and connection insulation surface anomalies indicating signs of reduced electrical insulation resistance.

Proven test(s) applicable to condition monitoring of the insulation are performed if testing is evaluated to be necessary after visual inspections identify degraded or damaged conditions that may adversely affect the performance of cable or connection insulation intended functions. Testing may include thermography and one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in procedures.

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced to:

1. Evaluate plant specific operating experience for previously identified and mitigated adverse localized environments' cumulative aging effects applicable to in scope cable and connection insulation to confirm that the insulation's intended functions continue to be supported during the subsequent period of extended operation.
2. Perform testing of a sample population when a large number of cables are identified as degraded. The sample size will be 20 percent of each affected cable and connection type with a maximum sample size of 25.

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

A.2.1.37 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 aging management program is an existing performance monitoring program. This aging management program manages the effects of reduced insulation resistance of non-EQ cable and connection electrical insulation in instrumentation circuits with sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

This program evaluates electrical insulation material for cables and connections subjected to an adverse localized environment at least once every 10 years.

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits aging management program will be enhanced to:

1. Add the electrical cables and connections for the following neutron monitors to the scope of the program:
 - a. Source range monitors
2. Add the electrical cables and connections for the following radiation monitors to the scope of the program:

- a. Reactor building ventilation radiation monitors
- 3. Review calibration or surveillance results of circuits in the scope of this program at least once every 10 years. The first periodic review will be performed prior to the subsequent period of extended operation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Reviews and tests that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.38 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 aging management program is an existing condition monitoring program. This program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), non-EQ medium-voltage power cables (operating voltage; 2 kV to 35 kV) that are within the scope of license renewal and potentially 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.

This program will manage reduced insulation resistance of inaccessible medium-voltage cables exposed to significant moisture through periodic testing to assess the condition of cable insulation. In addition, periodic actions are performed to prevent inaccessible cables from being exposed to significant moisture. In scope handholes will be inspected for water accumulation and the water will be removed as needed.

There are no inaccessible medium-voltage power cables designed for continuous wetting or submergence within the scope of this program.

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced to:

1. Perform cable testing of the circuits in the scope of this program at a frequency of at least once every six years. The first periodic test will be performed prior to the subsequent period of extended operation.
2. Perform inspections for water accumulation in handholes in the scope of this program after event driven occurrences that could result in water accumulation and cable submergence.
3. Perform annual inspections for water accumulation in handholes in the scope of this program. The first periodic inspection will be performed prior to the subsequent period of extended operation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Tests and inspections that are required to be

completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.39 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 aging management program is a new condition monitoring program. This program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), non-EQ instrument and control cables that are within the scope of license renewal and potentially 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 inaccessible instrument and control cables from being exposed to significant moisture. In scope manholes and associated accessible conduit ends are inspected for water accumulation and the water is removed, as needed.

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.40 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 aging management program is a new condition monitoring program. This program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), non-EQ low-voltage power cables (operating voltage less than 2 kV) that are within the scope of license renewal and potentially 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 inaccessible low-voltage power cables from being exposed to significant moisture. In scope manholes and associated accessible conduit ends are inspected for water accumulation and the water is removed as needed.

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be

completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.41 Metal Enclosed Bus

The Metal Enclosed Bus aging management program is an existing condition monitoring program that utilizes sampling. This program applies to metal enclosed bus within the scope of subsequent license renewal. Metal enclosed bus internal surfaces are visually inspected to detect age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. Metal enclosed bus insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination which may indicate overheating or aging degradation. The internal bus insulating supports are visually inspected for structural integrity and signs of cracks. Metal enclosed bus external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion. Accessible elastomers are visually inspected for degradation, including surface cracking, crazing, scuffing, changes in dimension (e.g. “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength.

A sample of accessible bolted connections is inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro-ohmmeter. Inspection of a sample population of bolted connections is performed at least once every ten years.

The Metal Enclosed Bus aging management program will be enhanced to:

1. Perform periodic inspections of the isophase bus from the main generator to the main step-up transformers to the station service transformer and a sample of metal enclosed bus bolted connections. The first periodic inspection will be performed prior to the subsequent period of extended operation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.1.42 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 aging management program is a new condition monitoring program that will require testing of a representative sample of electrical connections 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. The program will apply to electrical connections within the scope of subsequent license renewal that are not subject to EQ requirements. The following factors will be considered for sampling: voltage level (medium and low-voltage), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of each connector type population with a maximum sample of 25 constitutes a representative connector sample size. The specific type of test to be performed will be a proven method for detecting increased

resistance of the connection. This program does not implement visual inspections of cable connection insulation material as an alternative to testing.

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Tests and evaluations that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.2.2 Plant-Specific Aging Management Programs

None. The Nine Mile Point Nuclear Station, Unit 1 Subsequent License Renewal Application does not include plant-specific aging management programs.

A.3.0 NUREG-2191 Chapter X Aging Management Programs

A.3.1 Evaluation of Chapter X Aging Management Programs

Aging Management Programs evaluated in Chapter X of NUREG-2191 are associated with Time-Limited Aging Analysis for fatigue monitoring, neutron fluence monitoring, and environmental qualification of electric equipment. These programs are evaluated in this section.

A.3.1.1 Fatigue Monitoring

The Fatigue Monitoring aging management program is an existing program that manages fatigue damage of the reactor pressure vessel components, reactor coolant pressure boundary piping components, and other components per 10 CFR 54.21(c)(1)(iii).

The Fatigue Monitoring 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 fatigue analyses and environmentally assisted cumulative usage fatigue analyses. No NMP1 ANSI B31.1 or ASME Code Class 2 and 3 maximum allowable stress range reduction/expansion stress analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii); therefore, this program does not apply to these implicit analyses. There is one cycle-based flaw growth analysis dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) that applies to this program. There are no implicit fatigue analyses, fatigue waivers or exemption analyses that are based on cycle-based loading assumptions that have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). The program also monitors applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations.

The program manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the applicable structures and components by monitoring for design transient occurrences and the calculation of cumulative usage factors (CUF) and environmentally assisted cumulative usage factor (CUF_{en}) values. The program utilizes applicable acceptance criteria (limits) to verify the continued acceptability of existing analyses through transient occurrence counting and the calculation, trending, and projection of CUF and CUF_{en} values. The program verifies the

continued acceptability of existing analyses with periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits.

When a program acceptance criterion is exceeded or the severity of an actual transient exceeds the design transient definition, the condition is entered into the corrective action program and appropriate corrective actions, such as reanalysis, component or structure inspections, or component or structure repair, or replacement activities are implemented to ensure that design limits are not exceeded. Technical Specification requirements do not apply; the program manages cumulative fatigue damage in accordance with UFSAR Section V.A.4.0, "Cyclic Loads (Mechanical and Thermal)," Table V-2, "Operating Cycles and Transient Analysis Results."

A.3.1.2 Neutron Fluence Monitoring

The Neutron Fluence Monitoring aging management program is an existing condition monitoring program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel and reactor internal components to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessment for reactor internal components will remain within their applicable limits. The components evaluated by these analyses are the reactor pressure vessel shell and welds and reactor vessel internal components subject to reactor coolant and neutron flux environment which are fabricated from carbon or low alloy steel with stainless steel cladding, stainless steel, and nickel alloy materials.

The program has two aspects, one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB).

Monitoring is performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in NRC-approved reports. The methods and assumptions for projecting reactor pressure vessel (RPV) neutron fluence for the beltline region are consistent with NRC Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." The methods and assumptions used for the original beltline region are considered appropriate for the beltline region that has been extended to encompass materials projected to experience fluence in excess of 1×10^{17} n/cm² (E > 1 MeV) at 67 EFPY. There are three additional RPV plates and one additional weld added to the extended beltline of Unit 1 at 67 EFPY. The methods for projecting reactor vessel internal component fast neutron fluence values are not governed by regulatory guidance or requirements.

The program results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for reactor pressure vessel components. This includes, but is not limited to, the neutron fluence inputs for the reactor pressure vessel upper-shelf energy analyses (or equivalent margin analyses, as applicable to the CLB) and pressure-temperature limits analyses that are required to be performed in accordance with 10 CFR Part 50, Appendix G requirements. Comparisons to the neutron fluence inputs for other analyses include those for Upper Shelf Energy

(USE) analyses (A.4.2.2), Adjusted Reference Temperature (ART) analyses (A.4.2.3), RPV Pressure-Temperature (P-T) limits (A.4.2.4), mean RT_{NDT} and probability of failure analyses for the RPV circumferential and axial shell welds (A.4.2.5 and A.4.2.6), core shroud repair stabilizer assembly bracket preload relaxation analysis (A.4.2.7), and aging effect assessments for the reactor internals that are induced by neutron irradiation exposure mechanisms.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the Reactor Vessel Material Surveillance (A.2.1.19) program provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant Technical Specifications or in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

A.3.1.3 Environmental Qualification of Electric Equipment

The Environmental Qualification of Electric Equipment aging management program is an existing program that manages the aging of electrical equipment within the scope of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." The program implements the EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform their safety functions in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished, replaced, or have their qualification extended prior to or at the end of the equipment qualified life established in the evaluation so that the aging limit is not exceeded. Aging evaluations for EQ equipment that specify a qualification of at least 60 years are TLAAs for SLR.

This program is implemented in accordance with 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii). Along with the Environmental Qualification of Electric Equipment aging management program, the EQ program demonstrates the acceptability of the TLAA analysis under 10 CFR 54.21(c)(1) and is considered an AMP for the subsequent period of extended operation.

The Environmental Qualification of Electric Equipment aging management program will be enhanced to:

1. Visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic inspection will be performed prior to the subsequent period of extended operation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

A.4.0 Time-Limited Aging Analyses

A.4.1 Identification and Evaluation of Time-Limited Aging Analyses (TLAAs)

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 period of extended operation be provided. The TLAAs identified and evaluated to meet these requirements for Nine Mile Point Nuclear Station, Unit 1 (NMP1) are described in the following sections.

10 CFR 54.21(c)(2) also 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 period of extended operation. No plant-specific exemptions granted pursuant to 10 CFR 50.12 were identified for NMP1 that are based upon a TLAA. Therefore, no further evaluation is required for plant-specific exemptions granted pursuant to 10 CFR 50.12.

A.4.2 Reactor Pressure Vessel and Internals Neutron Embrittlement Analyses

10 CFR 50.60 requires that light-water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The current reactor pressure vessel embrittlement calculations for NMP1 that evaluate reduction of fracture toughness of the reactor pressure vessel beltline materials for 60 years are based upon a predicted end-of-license fluence applicable for 46 effective full power years (EFPY). These analyses have been identified as TLAAs as defined in 10 CFR 54.21(c) and have been re-evaluated for the increased neutron fluence associated with 80 years of operation as described in the subsections below.

A.4.2.1 Neutron Fluence Analyses

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter (flux) that contact the reactor pressure vessel (RPV) shell and its internal components over a given period of time. 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 loss of fracture toughness aging effect resulting from neutron fluence.

The transport calculations for NMP1 were carried out in R- θ and R-Z geometry using the Two-Dimensional Discrete Ordinates Code (DORT) and the BUGLE-96 cross-section library. The DORT code is an update of the DOT code which has been in use for this type of analysis for many years. The BUGLE-96 library is a 47-energy group ENDF/B-VI based data set produced specifically for light water reactor applications (an update of the earlier SAILOR library). Analysis above and below the active fuel length was carried out using the Three-Dimensional Transport Code (TORT). The TORT code uses the same methodology as the DORT code except for the extension into the third dimension. These transport codes have been used in developing the 80-year fluence projections and associated RPV embrittlement analyses.

Below is a summary of NMP1 historical operating power levels which have been considered in developing the 80-year fluence projections:

- The original licensed thermal power (OLTP) level for NMP1 was 1538 megawatts thermal (MWt).
- By Amendment No. 2 dated March 3, 1971, the NRC authorized an increase in the maximum thermal power level from 1538 MWt to the current licensed thermal power (CLTP) level of 1850 MWt. This is the current licensed thermal power limit for NMP1.

The current licensed thermal power level of 1850 MWt is the maximum power level evaluated for the subsequent period of extended operation.

A.4.2.1.1 Reactor Pressure Vessel Neutron Fluence Analyses

Reactor Pressure Vessel (RPV) fluence projections for 80 years and 67 EFPY have been developed using the NRC-approved Discrete Ordinate Transfer (DORT) methodology. The 67 EFPY fluence projection values have been used in the evaluation of the neutron embrittlement TLAAAs for RPV beltline materials, which include the RPV plate materials, welds, and nozzle forgings. Fluence projections have been developed to evaluate fluence-based RPV TLAAAs and to determine when specified fluence threshold values may be exceeded that are used to invoke specific aging management requirements, such as inspections, for these components.

These 67 EFPY fluence projections will be validated by the Neutron Fluence Monitoring (A.3.1.2) program during the subsequent period of extended operation.

The RPV beltline component fluence analyses have been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.1.2 Reactor Pressure Vessel Internals Neutron Fluence Analyses

The core region transport calculations were carried out using the two-dimensional Discrete Ordinates Code (DORT) and the BUGLE-96 cross section library. Analysis above and below the active fuel length was carried out using the Three-Dimensional Transport Code (TORT). The TORT code uses the same methodology as the DORT code except for the extension into the third dimension. These transport codes have been used in developing the 80-year fluence projections and associated Reactor Pressure Vessel (RPV) internal embrittlement analyses. The fluence projections have been developed for specific RPV internal components to evaluate fluence-based TLAAAs and to determine when specified fluence threshold values may be exceeded that are used to invoke specific aging management requirements, such as inspections, for these components.

The RPV internal component fluence analyses have been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.2 Reactor Pressure Vessel Upper-Shelf Energy (USE) Analyses

Appendix G of 10 CFR 50, Paragraph IV.A.1.a, states that reactor pressure vessel (RPV) beltline materials must have Charpy upper-shelf energy (USE) throughout the

life of the RPV of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The NMP1 RPV was designed and fabricated prior to the current requirements going into effect, and as a result, there is insufficient data available to establish the unirradiated USE value for beltline and extended beltline materials. As such, equivalent margin analysis (EMA) is used for all NMP1 beltline and extended beltline materials lacking unirradiated USE values. The EMA is also performed for all applicable USE beltline plate and weld materials for NMP1 that cannot satisfy the 50 ft-lb criterion. The current EMA analysis conservatively uses the existing acceptance criteria defined in BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guideline for License Renewal,” which are the maximum allowable percent decrease in USE for the BWR/2 plates and BWR/2-6 welds. Where initial unirradiated USE values are available, the material is evaluated in accordance with Regulatory Guide 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” using the equations in Regulatory Guide 1.162, “Format and Content of Report for Thermal Annealing of Reactor Pressure Vessels,” which model the Charpy USE decrease curves.

To evaluate USE for 80 years, the 67 EFPY fluence values described in Section A.4.2.1 for reactor beltline and extended beltline materials have been used to develop revised EMA values that have been compared to the applicable design limits from BWRVIP-74-A. The USE values for NMP1 reactor vessel beltline and extended beltline materials have been satisfactorily evaluated for the subsequent period of extended operation based upon the updated EMA values determined using 80-year (67 EFPY) fluence projections.

Therefore, the equivalent margin analyses have been successfully projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.3 Reactor Pressure Vessel Adjusted Reference Temperature (ART) Analyses

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the P-T limit curves to account for irradiation effects. The initial nil-ductility reference temperature (RT_{NDT}) is the temperature at which an unirradiated ferritic steel material changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the ASME Code. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50, Appendix G defines the fracture toughness requirements for the life of 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}) determines how much higher the vessel temperature must be raised for the material to continue to act in a ductile manner. The ART is defined as: $Initial\ RT_{NDT} + \Delta RT_{NDT} + Margin$. Since the ΔRT_{NDT} value is a function of 46 EFPY fluence in the current ART calculations associated with the 60-year licensed operating period, these ART analyses have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

Eighty-year, 67 EFPY, ART values have been determined for NMP1 beltline materials using the methodology specified in Regulatory Guide 1.99, Revision 2. The 67 EFPY ART values of the limiting beltline material remains below 179.5 degrees F, which is the RT_{NDT} limit.

The 67 EFPY ART analyses have been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(ii).

A.4.2.4 Reactor Pressure Vessel Pressure-Temperature (P-T) Limits

10 CFR 50 Appendix G requires that the reactor pressure vessel (RPV) be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the minimum acceptable reactor coolant temperature as a function of reactor pressure. As the RPV is exposed to increased neutron irradiation over time, its fracture toughness is reduced. The P-T limits must account for the change in material properties due to anticipated RPV fluence.

The currently licensed P-T limit curves are located in the Pressure-Temperature Limits Report (PTLR). The currently licensed P-T curves were developed for up to 46 EFPY.

In accordance with NUREG-2192, Revision 1, Section 4.2.2.1.4, for plants that have approved PTLRs, the P-T limits for the subsequent period of extended operation (SPEO) will be updated at the appropriate time through the plant's Administrative Controls Section of the Technical Specifications and the plant's PTLR process. NMP1 Technical Specification 6.6.7, "Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)," defines the administrative controls. This process will ensure that the P-T limits for the SPEO will be updated prior to expiration of the 46 EFPY P-T limit curves. The analyses supporting the P-T curves consider all locations within the reactor coolant pressure boundary as they do in the current P-T curves. Maintenance of the P-T limits during the SPEO will be managed using the PTLR process as described above.

Therefore, the effects of aging on the intended function(s) of the RPV will be adequately managed through the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). Pressure-Temperature limits will be updated prior to 46 EFPY in accordance with the Administrative Section of the Technical Specifications.

A.4.2.5 Reactor Pressure Vessel Circumferential Weld Failure Probability Analysis

NMP1 has previously applied for and been granted relief from reactor pressure vessel (RPV) circumferential weld inspection via relief request 1ISI-001A, as described in the associated NRC safety evaluation report (SER), dated August 3, 2009 (ADAMS Accession No. ML092010256). The relief from inspection is based on assessment of the probability of failure of the limiting circumferential weld. This assessment is based on 46 EFPY fluence values associated with 60 years of operation.

BWRVIP-329-A, "BWR Vessel Internals Program, Updated Probabilistic Fracture Mechanics Analyses for BWR RPV Welds to Address Extended Operations,"

approved in December 2021, and the associated NRC SER provide additional technical basis for reduction in inspection of RPV circumferential welds and an assessment of axial weld integrity for extended operation of up to 80 years. Plant-specific RPV dimensions for NMP1 have been evaluated for the applicability criteria in BWRVIP-329-A, Section 5.0, “Summary and Conclusions.” This confirmed that the NMP1 RPV is within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

The limiting maximum reference temperatures (RT_{MAX}) at 67 EFPY were calculated using plant-specific material chemistry, initial unirradiated RT_{NDT} , and projected 80-year fluence values for the NMP1 RPV plates and welds. The end-of-interval (EOI) is defined as 80 years, which is equivalent to 67 EFPY for neutron fluence. The EOI RT_{MAX} values for all NMP1 plates and welds meet the acceptability criteria for the limiting plates, circumferential welds, and axial welds in BWRVIP-329-A. Therefore, this evaluation shows that the NMP1 RPV meets the acceptance criteria of BWRVIP-329-A, Section 5.0.

Re-application for relief from RPV circumferential weld examinations will be made in accordance with 10 CFR 50.55(a)(z)(1) for NRC review and approval prior to exceeding 46 EFPY. The plant-specific information described above demonstrates that at the end of the subsequent period of extended operation, the circumferential beltline weld materials meet the limiting conditional failure probability for circumferential welds specified in the NRC’s final SER of BWRVIP-329-A. These analyses will be managed in accordance with 10 CFR 54.21(c)(1)(iii) by requesting relief from circumferential weld inspection using the 10 CFR 50.55a process.

A.4.2.6 Reactor Pressure Vessel Axial Weld Failure Probability Analysis

The recommendations for inspection of reactor pressure vessel (RPV) shell welds in BWRVIP-05, “BWR Vessel and Internals Project, BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations,” include examination recommendations of BWR RPV axial welds. NMP1 successfully evaluated axial weld failure probabilities for 60 years of operation at 46 effective full power years (EFPY), as described in an NRC safety evaluation report (SER) dated August 3, 2009 (ADAMS Accession No. ML092010256). The current axial weld failure probability analysis for NMP1, that was included in relief request 1ISI-001A, is based upon 46 EFPY fluence values associated with 60 years of operation.

BWRVIP-329-A, “BWR Vessel Internals Program, Updated Probabilistic Fracture Mechanics Analyses for BWR RPV Welds to Address Extended Operations,” approved in December 2021, and the associated NRC SER provide additional technical basis for an assessment of axial weld integrity for extended operation of up to 80 years. Plant-specific RPV dimensions and material chemistry for NMP1 have been evaluated for the applicability criteria in BWRVIP-329-A Section 5.0, “Summary and Conclusions.” This confirmed that the NMP1 RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

The limiting maximum reference temperatures (RT_{MAX}) at 67 EFPY have been calculated using plant-specific material chemistry, initial unirradiated RT_{NDT} , and projected 80-year fluence values for the NMP1 RPV plates and welds. The end-of-interval (EOI) is defined as 80 years, which is equivalent to 67 EFPY for neutron

fluence. The EOI RT_{MAX} values for NMP1 RPV plates and welds meet the acceptability criteria for the limiting plate, circumferential weld, and axial weld in BWRVIP-329-A. Therefore, this evaluation shows that the NMP1 RPVs meet the acceptance criteria of BWRVIP-329-A Section 5.0.

The plant-specific information described above demonstrates that at the end of the subsequent period of extended operation, the axial beltline weld materials meet the limiting conditional failure probability for axial welds specified in the NRC's final SER of BWRVIP-329-A. Therefore, the RPV axial weld failure probability analyses have been successfully evaluated through the subsequent period of extended operation, using the latest NRC approved methodology, in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.7 Core Shroud Stabilizer Assembly Preload Relaxation Analysis

Inservice inspections identified indications in and near the heat-affected zone of the core shroud horizontal and vertical welds caused by intergranular stress corrosion cracking (IGSCC). A core shroud repair was designed to structurally replace the core shroud's horizontal welds H1 through H7 and was installed in 1995. The design consists of four shroud stabilizer tie-rod assemblies combined with core plate wedges, which were installed approximately 90 degrees apart in the core shroud/reactor pressure vessel annulus, between attachment points at the top of the upper core shroud head flange and the core shroud conical support. Each tie-rod assembly consists of a tie-rod, upper support, upper spring, middle support, lower lateral and axial springs, and lower support.

The design of the tie-rod stabilizer assemblies accounted for a preload relaxation of five percent for the upper and lower springs due to an end-of-life fluence threshold.

For the subsequent license renewal application, fluence projections were prepared for 80 years at 67 effective full power years (EFPY). The maximum 67 EFPY exposure to the shroud stabilizer upper spring assemblies is $1.64E+19$ n/cm² and $1.82E+19$ n/cm² for the lower spring assemblies, which is less than the fluence assumed in the original design.

Therefore, the core shroud stabilizer tie-rod assemblies preload relaxation due to fluence exposure has been successfully demonstrated to remain valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3 Metal Fatigue Analyses

Fatigue analyses are required on components designed to ASME, Section III, Class 1 and Class MC. In addition, other codes such as ASME Section III, Class 2 and 3, and ASA (ANSI) B31.1 may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. Nine Mile Point Nuclear Station, Unit 1 fatigue TLAAs are evaluated using 80-year transient occurrence and cumulative usage projections. Each of these fatigue analyses and evaluations are considered to be Time-Limited Aging Analyses (TLAAAs) requiring evaluation for the subsequent period of extended operation in accordance with 10 CFR 54.21(c) as described below.

A.4.3.1 Transient Cycle and Cumulative Usage Projections for 80 years

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients usually described in design specifications. 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. Since the existing fatigue analyses are based upon a number of transient cycles postulated to bound 60 years of service, projection of the transient cycles through the subsequent period of extended operation is required to demonstrate that the analyses remain valid.

Projections of the transient cycle occurrences through the subsequent period of extended operations were developed for 80 years and used as input to calculate projected 80-year cumulative usage factor (CUF) and environmentally assisted cumulative usage factor (CUF_{en}) values to determine whether the existing analyses remain valid for 80 years. The number of transient cycle occurrences, CUF values, and CUF_{en} values have been projected through the subsequent period of extended operation. The following fatigue TLAAAs have been dispositioned using the projected number of transient cycles occurrences, CUF values, and CUF_{en} values through the subsequent period of extended operation.

A.4.3.2 Reactor Vessel and Piping Fatigue Analyses

The NMP1 reactor pressure vessel (RPV) was originally designed for 40 years of service in accordance with the ASME Code, Section I, Power Boilers, 1962 Edition and Addenda plus the Nuclear Code Cases applicable on December 11, 1963. Fatigue usage factors were computed for reactor vessel critical locations using methods similar or identical to ASME Section III. Based on the number and type of design basis transients for the 40-year design life, cumulative usage factor (CUF) values were calculated for the critical locations of the RPV, where it was shown that all CUFs were less than 1.0.

The NMPNS first license renewal application committed to implementing the Fatigue Monitoring (A.3.1.1) program to include automated transient occurrence counting and automated calculation and tracking of fatigue CUFs. As a result, SI:FatiguePro™ software was implemented at NMP1 in 2007.

Piping at NMP1 was originally designed in accordance with the ASA (ANSI) B31.1 Code, 1955 Edition, including applicable case interpretations for nuclear service, which did not include requirements for explicit fatigue analyses. For the purposes of fatigue monitoring only, fatigue calculations were performed for selected locations consistent with the guidance in ASME Section III. These selected locations were then added to SI:FatiguePro™ software to ensure accumulated CUF values for each location will not exceed the ASME Section III design limit of 1.0. The remaining NMP1 piping components that were not implemented into the Fatigue Monitoring (A.3.1.1) program use implicit fatigue analyses, which also are TLAAAs and are addressed in Section A.4.3.4.

Eighty-year projected values of CUF and CUF_{en} for all locations remain less than the ASME Section III acceptance criterion through the subsequent period of extended operation. To ensure the projected CUF and CUF_{en} values remain acceptable for the 80-year period of operation, the Fatigue Monitoring (A.3.1.1) program will monitor

cumulative CUF and CUF_{en} for limiting locations through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.3 Fatigue of the Emergency Condensers

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for NMP1 in which fatigue analyses were performed for the emergency condensers. The tube and shell sides of the emergency condensers were designed in accordance with ASME Section III, as Class 2 and 3 components, respectively.

In 1997, failures of the original tubing were attributed to thermal fatigue resulting from leakage past the condensate return line. As a result of this failure, a subsequent modification and repair was performed which replaced the tube bundles for each of the emergency condensers. Fatigue loading was evaluated by calculating the alternating stresses associated with applicable design transients to determine a cumulative usage factor (CUF) based on the number of anticipated transients for the life of the condensers.

While the CUF values of the modified emergency condensers were all shown to be less than 1.0, bounding locations were included in the SI:FatiguePro™ software for monitoring.

The Fatigue Monitoring (A.3.1.1) program currently uses SI:FatiguePro™ to monitor fatigue of the four most limiting sub-component locations on the emergency condensers by computing the CUF-to-date values based upon the cumulative numbers of fatigue transient cycles that have occurred as of the monitoring date. The Fatigue Monitoring (A.3.1.1) program includes requirements that initiate corrective actions if any accumulated CUF or CUF_{en} values exceed 80 percent of the ASME Section III acceptance criteria. Therefore, the Fatigue Monitoring (A.3.1.1) program will manage the TLAA(s) and associated effects of fatigue on the emergency condenser through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.4 ASME Section III, Class 2 and 3, and ANSI B31.1 Allowable Stress Analyses and HELB Exclusions of Recirculation Piping Analysis

The NMP1 safety-related piping, and other piping that is in scope for license renewal was originally designed in accordance with the 1955 Edition of the ASA (ANSI) B31.1 Power Piping Code.

Piping systems designed in accordance with ASME Section III, Class 2 and 3, and B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but rather, cyclic loading is implicitly considered in a simplified manner in the design process. ASME Section III, Class 2 and 3, and B31.1 design rules require a stress range reduction factor to be used based on the number of thermal and pressure occurrences expected during the component operating lifetime. If the total number of occurrences is expected to be 7,000 or less, a stress range reduction factor of 1.0 is applied. For greater numbers of fatigue occurrences, a stress range reduction factor of less than 1.0 is applied, which reduces the allowable stress range. These are typically referred to as "implicit" fatigue TLAAs.

Typically, locations that are excluded from high-energy line break (HELB) consideration are based on time-limited evaluations (e.g., implicit fatigue TLAAAs) based on the guidance in Branch Technical Position (BTP) MEB 3-1, "Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment." UFSAR Section XVI, "Special Topics Report," Subsection D.2.1, "Inside Primary Containment," and Subsection D.2.2, "Outside Primary Containment," document how the effects of pipe whip from high-energy breaks inside containment and outside containment were evaluated, respectively. These sections describe that the 12 high-energy systems inside containment, listed in UFSAR Table XVI-28, "High-Energy Systems – Insider Containment," and the 12 energy systems outside containment, listed in UFSAR Table XVI-29, "High-Energy Systems – Outside Containment," were evaluated for HELB. It was assumed that any one of these lines could break anywhere inside primary containment or anywhere outside of primary containment. Therefore, at NMP1 no locations inside or outside of containment on piping segments for these systems were excluded from the original HELB analyses.

However, a portion of the reactor recirculation system was evaluated in 1990 in response to NRC Information Notice 89-55, "Degradation of Containment Isolation Capability by a High-Energy Line Break." The evaluation excluded some recirculation system piping segments from further consideration using the guidance in Branch Technical Position MEB 3-1, Section B.1.C(2) which allows the exclusions of high-energy pipe segments with calculated stresses less than $0.8 (1.8Sh + SA)$. Since the allowable stress (Sh) and stress range (SA) are a function of the stress range reduction factor for cyclic conditions, further evaluation would be necessary if the actual number of full range temperature occurrences exceed a value of 7,000. If non-class 1 high-energy piping locations in the reactor recirculation system that were not selected for HELB analyses in response to Information Notice 89-55 exceed 7,000 thermal occurrences, then the stress range reduction factor would have to be applied (e.g., less than 1.0) and the HELB selection methodology in the 1990 evaluation may require the addition of new locations.

Portions of the following license renewal piping systems were designed in accordance with ASME Section III, Class 2, Class 3, or B31.1 requirements and are only affected by the same pressure and temperature transients as the reactor coolant system. These are: Condenser Air Removal and Off-Gas System, Control Rod Drive System, Core Spray System, Feedwater/High Pressure Coolant Injection System, Liquid Poison System, Main Steam System, Main Turbine and Auxiliaries System, Radioactive Waste System (Feedwater Vent Piping and Recirculation Pump Seal Leak Detection Drain Lines), Reactor Pressure Vessel Instrumentation System, Reactor Recirculation System, Sampling System (Reactor Recirculation Sampling Line and Feedwater-HPCI Sample Lines), and Shutdown Cooling System. Conservative 80-year projections of these systems demonstrate that the total number of thermal cycles for these piping systems will not exceed 57 percent of the 7,000 cycle threshold that would result in a reduction in the stress range reduction factor. Therefore, the stress range reduction factors originally applied for the piping sub-systems within these piping systems remain applicable and these implicit TLAAAs remain valid through the subsequent period of extended operation (SPEO). Also, the original selection scope for the 1990 HELB evaluation of the Reactor Recirculation System remains valid for the SPEO.

Some systems or portions of systems within the scope of subsequent license renewal are affected by thermal and pressure transients that are different than reactor coolant system transients. These are the Electric Steam Boiler System, Emergency Cooling System, Emergency Diesel Generator System (engine exhaust piping), Fire Detection and Protection System (diesel fire pump engine exhaust piping), Reactor Water Cleanup System, and Sampling System (main steam sample lines and reactor water cleanup regenerative heat exchanger outlet sample lines). An operational review of these systems concluded that the total number of thermal cycles that these systems are conservatively projected to experience through the subsequent period of extended operation are substantially less than the 7,000-cycle based threshold.

Therefore, the stress range reduction factors originally selected for piping within these piping systems remain applicable and these TLAAAs are valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.5 Environmentally Assisted Fatigue Analysis

NUREG-2191, Revision 1, Section X.M1, "Fatigue Monitoring," aging management program provides guidance for evaluating the effects of reactor water environment on the fatigue life of ASME Section III components that are in contact with reactor coolant. One acceptable method for satisfying this guidance is to assess the impact of the reactor coolant environment on a sample set of critical components as described in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." Additional component locations are evaluated if they are considered to be more limiting than those listed in NUREG/CR-6260.

Environmental fatigue calculations were performed for component locations listed in NUREG/CR-6260 for the older vintage BWR. In order to ensure that other locations that may not be bounded by the NUREG/CR-6260 locations were considered, environmental fatigue screening calculations were performed for all reactor pressure vessel, piping, and other component locations that have an identified reported cumulative usage factor (CUF) value in the governing stress reports and are exposed to reactor coolant.

Component specific environmentally assisted fatigue evaluations for all identified components were then performed in accordance with NUREG/CR-6909, Revision 1, "Effect of LWR Water Environments on the Fatigue Life of Reactor Materials."

These environmental fatigue analyses will be managed by the Fatigue Monitoring (A.3.1.1) program in the same manner as the ASME Section III, Class 1 fatigue analyses. The program ensures that the environmental assisted cumulative usage factors (CUF_{en}) are maintained below the design limit of 1.0. If a CUF_{en} limit is approached, corrective actions are triggered to prevent exceeding the limit.

The effects of environmentally assisted fatigue aging on the intended functions will be adequately managed by the Fatigue Monitoring (A.3.1.1) program through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.6 Reactor Vessel Internals Fatigue Analyses

The NMP1 reactor vessel internals were not designed in accordance with ASME Section III. Therefore, determination of cumulative usage factors (CUFs) was not required. However, a CUF value was identified for the steam dryer support brackets over the original 40-year reactor pressure vessel life, as discussed in Section A.4.3.6.4. In addition, fatigue analyses were performed for the core shroud repair hardware as described in Sections A.4.3.6.1, A.4.3.6.2, and A.4.3.6.3. Note, Section A.4.3.6.1 discusses the original conical support and tie-rod fatigue analysis, a separate tie-rod fatigue analysis was performed for a subsequent modification which addressed other sub-components of the tie-rods, as discussed in Section A.4.3.6.3.

A.4.3.6.1 Core Shroud Stabilizer Tie Rod and Conical Support Fatigue Analysis

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for NMP1 in which a fatigue analysis of the core shroud stabilizer assemblies (tie-rods) was performed using ASME Section III methodology.

A core shroud repair was installed in 1995 to structurally replace the core shroud's horizontal welds H1 through H7. The design consists of four shroud stabilizer tie-rod assemblies combined with core plate wedges, which were installed approximately 90 degrees apart in the core shroud/reactor pressure vessel annulus, between attachment points at the top of the upper core shroud head flange and the core shroud conical support.

General Electric documented the fatigue analysis and cumulative usage factor (CUF) value of the shroud conical support (tie-rod attachment points) using transients and transient occurrences assumed to occur over the service life of the repair. The maximum CUF for any part of the conical support and tie-rods or their attachment points was 0.0081 for the life of the repair.

The fatigue analysis of the conical support and tie-rods has been reevaluated for the subsequent period of extended operation using the 80-year projected transient occurrences. The resultant CUF is 0.0085, which is significantly less than the ASME Code Section III design limit of 1.0.

Therefore, the fatigue damage aging effect on the core shroud support stabilizer tie-rod and conical supports has been successfully projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.3.6.2 Core Shroud Vertical Weld Repair Clamps Fatigue Analysis

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for NMP1 in which a fatigue analysis of the core shroud vertical weld repair clamps was performed using methodology in ASME Section III, Subsection NG, 1989 edition. This repair was installed in 1999 to structurally replace the core shroud's vertical welds V9 and V10. The design consists of two clamps that bridge across flawed welds V9 and V10.

The design analysis of the vertical weld repair clamps documented a cumulative usage factor (CUF) value using transients and transient occurrences assumed to

occur over the service life of the repair. The maximum CUF value was 0.0236 for the life of the repair.

The fatigue analysis of the repair clamps has been reevaluated for the subsequent period of extended operation using the 80-year projected transient occurrences. The resultant bounding CUF is 0.0284, which is significantly less than the ASME Code Section III design limit of 1.0. Therefore, the fatigue damage aging effect on the vertical weld repair clamps has been successfully projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.3.6.3 Core Shroud Stabilizer Modified Upper Supports Fatigue Analyses

The NMP1 shroud stabilizer assembly upper supports installed in 1995 (Section A.4.3.6.1) were replaced in 2007 after a potential for high peak stresses in the original shroud stabilizer upper support design was discovered. The replacement hardware was analyzed for fatigue in accordance with the ASME Section III, Subsection NG, 2001 edition, including the 2003 addenda. General Electric (GE) documented the fatigue analysis and cumulative usage factor (CUF) values of the shroud stabilizer modified upper support components in a proprietary report using transients and transient occurrences assumed to occur over a 40-year component life.

The projected number of transient occurrences through the subsequent period of extended operation assumed in the fatigue analysis of the modified upper support components are all less than the assumed occurrences in the corresponding fatigue analysis documented in the proprietary GE report. Therefore, the calculated CUF values for these components will not exceed the ASME Section III limit during the subsequent period of extended operation. The assumed transient occurrences for the original design life of the modified upper supports remain valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.6.4 Steam Dryer Support Bracket Fatigue Analysis

The NMP1 steam dryer support brackets were analyzed for cyclic loading at the “U-plate to bracket weld” location for 40 years of operation. The analysis of the steam dryer support brackets documented a cumulative usage factor (CUF) value of 0.268, based on an assumed 402 cycles and an allowable number of 1,500 cycles.

The fatigue analysis of the steam dryer support brackets has been reevaluated for the subsequent period of extended operation using a total of 500 transient occurrences. The 500 transient occurrences are based on the 80-year projected occurrences documented for startup/shutdown, scram, loss of feedwater flow, overpressure to 1,250 psig, overpressure to 1,375 psig, and an additional 97 thermal cycles to account for margin. The resultant 80-year CUF is 0.333, which is less than the defined acceptance criteria of 0.8. Therefore, the fatigue damage aging effect on the steam dryer support brackets has been successfully projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.4 Environmental Qualification of Electric Equipment

A.4.4.1 Environmental Qualification of Electric Equipment

Thermal, radiation, and cyclical aging analyses of plant electrical components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses for NMP1. The NRC has established nuclear station Environmental Qualification (EQ) requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function 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, or post-LOCA environment. 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 (A.3.1.3) program will manage the effects of aging for the components associated with the environmental qualification through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. Reanalysis of an aging evaluation to extend the qualifications of components 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 component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid.

The Environmental Qualification of Electric Equipment (A.3.1.3) program has been demonstrated to be capable of programmatically managing the qualified lives of the electrical components falling within the scope of the program. The effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.5 Concrete Containment Tendon Prestress Analysis

The NMP1 containment does not have pre-stressed tendons. As such, this topic is not a TLAA.

A.4.6 Primary Containment Fatigue Analyses

Subsequent to the original design, the Nine Mile Point Nuclear Station, Unit 1 (NMP1) primary containment was reanalyzed in response to the discovery of additional hydrodynamic loads not considered in the original design of the Mark I containment. As a result, General Electric initiated the Mark I Containment Program. The detailed guidance of the long-term program is contained in NRC NUREG-0661, "Safety Evaluation Report Mark I Containment Long-Term Program, Resolution of Generic Technical Activity A-7," and its supplements, which describe the generic hydrodynamic load definition and structural acceptance criteria consistent with the

requirements of the applicable codes and standards. The NMP1 primary containment was reanalyzed to evaluate the effects of the “new” hydrodynamic loads resulting from a blowdown into the suppression chamber during a postulated loss of coolant accident or an electromatic relief valve (ERV) discharge. Components of the primary containment that were reanalyzed included the torus shell, external support system, vent header system and internal structures, and piping attached to the torus, (including shell penetrations, internal piping, and supports); and were summarized in the Plant Unique Analysis Report (PUAR) Volumes I and II. As such, these components were analyzed for fatigue, therefore these analyses are considered TLAAAs.

In addition, the main steam piping drywell penetrations and the six ERV expansion joint bellows were previously replaced and designed to accommodate movements and cyclic requirements. As such, the evaluations of main steam piping penetration bellows and ERV expansion joint bellows are considered TLAAAs.

The spent fuel pool (SFP) underwent a planned modification to increase the storage capacity of the pool. Part of this work involved analyzing the SFP liner and new SFP storage racks for fatigue and, therefore, the analyses are considered TLAAAs.

A.4.6.1 Torus Shell Fatigue Analysis

Nine Mile Point Nuclear Station’s first license renewal application documented a TLAA for NMP1 in which subsequent to the original design, fatigue analysis of the torus shell due to new hydrodynamic loads were developed. The additional loads result from blowdown into the suppression chamber (torus) during a postulated loss of coolant accident and loads that could occur during normal operation, such as safety relief valve discharge. The results of the analyses of these effects were presented in the Plant Unique Analysis Report (PUAR).

The Fatigue Monitoring (A.3.1.1) program currently uses SI:FatiguePro™ to monitor fatigue of the bounding torus shell and external support system location, computing cumulative usage factor (CUF) to date values based upon the cumulative numbers of transient occurrences that have occurred as of the monitoring date.

Therefore, the Fatigue Monitoring (A.3.1.1) program will manage this TLAA and associated effects of fatigue on the torus shell through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.2 Vent System Fatigue Analysis

Nine Mile Point Nuclear Station’s first license renewal application documented a TLAA for NMP1 in which new hydrodynamic loads were identified subsequent to the original design of the Mark I containment system. The results of the analyses of these effects were presented in the Plant Unique Analysis Report (PUAR).

The fatigue analyses of the vent system evaluated fatigue on eight separate locations of the vent system, in which it was conservatively assumed that all maximum stresses occur simultaneously, and that all cycles reach these maximum values. The cumulative usage factors (CUFs) for all vent system locations were calculated considering the stresses associated with loadings due to chugging, which

is an accident condition loading. Normal and upset transients were not considered in this calculation.

A reevaluation of the original analysis was issued to account for the effect of increased stresses resulting from water which had accumulated in the vent header spherical intersections and reevaluated the fatigue of the components to account for a higher frequency of the chugging load. The maximum CUF determined in the reevaluation was 0.86 for the vent header/vent pipe spherical intersection location, based on the stresses developed during a postulated accident.

The fatigue analyses of the vent system only considered the stresses from chugging developed during a postulated accident. Since the postulated accident is considered a one-time event, which NMP1 has not experienced, the transient occurrences that were assumed in the fatigue analysis of the vent system are valid for 80 years in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.3 Torus Attached Piping Analysis

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA associated with the Mark I Containment Long Term Program modifications to the torus attached piping (TAP) and safety relief valve (SRV) piping. Both the modified TAP and SRV piping were evaluated by a generic fatigue analysis for Class 2 and 3 piping, which was submitted by the Mark I Containment Owners Group (MPR-751) for NRC approval. This generic analysis documented the stress results for the most limiting piping systems and locations for each plant evaluated. The generic analysis assumed 500 SRV actuations, five operating basis earthquakes, and one accident condition consisting either of a design basis accident (DBA) or intermediate break accident/small break accident (IBA/SBA) for a 40-year plant lifetime.

In the generic analysis, the results of the two most limiting locations at NMP1 were documented. These were the torus-attached piping associated with torus penetration XS-326 and torus-attached piping associated with torus penetration XS-337. The maximum cumulative usage factor (CUF) was associated with torus-attached piping XS-337 with a CUF value of 0.036 for 40-years.

The Fatigue Monitoring (A.3.1.1) program uses SI:FatiguePro™ to monitor fatigue of these two bounding component locations, computing the CUF-to-date values based upon the cumulative numbers of fatigue transient occurrences that have occurred as of the monitoring date.

Therefore, the effects of aging on the intended function(s) of the TAP will be managed by the Fatigue Monitoring (A.3.1.1) program through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.4 Fatigue of Primary Containment Penetrations

A.4.6.4.1 Safety Relief Valve Penetration Fatigue Analysis

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA associated with a fatigue analysis of the safety relief valve (SRV) penetrations

performed in accordance with ASME Section III, 1977 Edition through the summer 1977 Addenda.

The SRV penetration component specific stress and fatigue analysis determined an allowable of 60,000 stress cycles. This reported number of allowable stress cycles was based on an alternating stress value associated with an intermediate break/small break accident (IBA/SBA) load case.

For the subsequent license renewal application, even though SRV actuations during normal operation were not included in the original evaluation, for conservatism the loadings associated with SRV actuations during normal operating conditions were considered using 80-year SRV actuation projections. Using the guidance in the generic Mark I Containment Report (MPR-751), the number of stress cycles associated with the projected 80-year SRV actuations during normal operations were added to the stress cycles associated with an IBA/SBA. This resulted in a total of 20,950 stress cycles for 80 years which is significantly less than the allowable of 60,000 stress cycles. Therefore, the fatigue analysis of the SRV penetrations remains valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.4.2 Torus Attached Piping Penetrations Fatigue Analyses

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for NMP1 in which fatigue analyses of the torus attached piping (TAP) penetrations were performed in accordance with ASME Section III, 1977 Edition through the summer 1977 Addenda.

Specific stress and fatigue analyses were performed for the TAP penetrations where each analysis considered the loadings associated with a postulated loss of coolant accident including earthquake loads. For each of the TAP penetration specific analyses, the maximum number of assumed stress cycles for all loading events was estimated to be 10,000.

The analyses of all the small bore TAP penetrations and a portion of the large bore TAP penetrations determined the number of allowable cycles based on the stresses generated during a design basis accident (DBA). The maximum cumulative usage factor (CUF) calculated from the TAP penetration analyses based on a DBA case was 0.962 for the small bore torus drain line penetrations XS-362 and XS-363. This was based on an assumed 10,000 stress cycles and an allowable of 10,400 stress cycles.

The remaining portions of the large bore penetration analyses determined the number of allowable cycles based on an intermediate break/small break accident (IBA/SBA) case. The maximum CUF calculated for these TAP penetrations was 0.38 for containment spray suction pump TAP penetrations XS-342, XS-324, XS-341, and XS-325 based on an assumed 10,000 stress cycles and an allowable of 26,000 stress cycles.

These fatigue analyses of the TAP penetrations did not consider safety relief valve (SRV) actuations during normal operating conditions. The allowable stress cycles were based on only postulated accidents and earthquake loadings.

For the subsequent license renewal application, even though SRV actuations during normal operation were not included in the fatigue analyses, for conservatism the loadings associated with SRV actuations during normal operating conditions were considered using 80-year SRV actuation projections. Using the guidance in the generic Mark I Containment Report (MPR-751), the number of stress cycles associated with the projected 80-year SRV actuations during normal operation were added to stress cycles associated with either a DBA or IBA/SBA. The results demonstrated that except for penetrations XS-333 and XS-337, the remaining TAP penetration fatigue analyses were valid for the subsequent period of extended operation. Therefore, the fatigue analyses of the TAP penetrations (except for XS-333 and XS-337) remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

For TAP penetrations XS-333 and XS-337, a conservative discrepancy was identified in the number of allowable cycles in the original analyses. This condition was entered into the corrective action program for resolution, and the number of allowable cycles for penetrations XS-333 and XS-337 were revised to 76,528 and 157,081, respectively. Using the guidance in the generic Mark I Containment Report (MPR-751), the number of stress cycles associated with the projected 80-year SRV actuations during normal operations were added to stress cycles associated with a DBA or an IBA/SBA. The results were 5,761 (for XS-333) and 24,930 (for XS-337) stress cycles over 80 years, as compared to the allowables of 76,528 and 157,081 stress cycles. Therefore, for these two updated design analysis the number of allowable stress cycles has been successfully revised for 80 years of operations in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.6.5 Safety Relief Valve Piping Supports Fatigue Analyses

The Plant Unique Analysis Report (PUAR) reported a number of modifications that were performed for the safety relief valve (SRV) piping supports. Fatigue analyses were performed for a subset of the SRV piping supports that attach to the main vent piping and the vent sphere/vent header intersections.

For each of the SRV support fatigue analyses the maximum number of assumed stress cycles for all loading events was estimated to be 10,000, and the number of allowable stress cycles were calculated based on the stresses generated during a design basis accident (DBA). The maximum cumulative usage factor (CUF) calculated for the SRV supports was 0.91, for the lower-rigid support in the main vent piping, based on an assumed 10,000 stress cycles and an allowable of 11,000 cycles.

The fatigue analyses of the SRV supports did not consider SRV actuations during normal operating conditions. The allowable stress cycles were based on postulated accident and earthquake loadings.

For the subsequent license renewal application, even though SRV actuations during normal operation were not included in the original fatigue analyses, for conservatism, the loadings associated with SRV actuations during normal operating conditions were considered using 80-year SRV actuation projections. Using the guidance in the generic Mark I Containment Report (MPR-751), the number of stress cycles associated with the projected 80-year SRV actuations during normal operations were added to stress cycles associated with a DBA. The results were 2,179 stress cycles

over 80 years, as compared to the allowable of 11,000 stress cycles. Therefore, the fatigue analyses of the SRV piping supports remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.6 Main Steam Piping Penetration Bellows Cycle Limits

The main steam piping drywell penetrations (PENET-X-2A/B) were modified between 1990 and 1991, by adding "clam-shell" expansion joint bellows to accommodate thermal expansion as well as any movement due to a line rupture. The internal and external bellows were designed for 65,000 and 52,000 design cycles, respectively, and 200 incident cycles each. These cycles are associated with accommodating the maximum movements of any one or a combination of normal operating conditions (startup and shutdown transients) or an incident condition when a failure occurs (design basis accident (DBA)).

Nine Mile Point Nuclear Station, Unit 1 has not experienced a DBA, and the assumed 200 cycles associated with the movements of a DBA are bounding during the subsequent period of extended operation. Two hundred and eighteen startup and 216 shutdown transient occurrences are projected for 80 years. These projections are both significantly less than the 65,000 cycles specified for the internal bellows and 52,000 cycles specified for the external bellows.

Therefore, the transient conditions and associated cycle occurrences that were assumed for the design life of the main steam piping penetration bellows remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.7 Electromatic Relief Valve Bellows Cycle Limits

There are six expansion joint bellows (EXJBJ-66-01R through EXJBJ-66-06R) connecting the electromatic relief valve (ERV) enclosure discharge to the discharge piping that goes to the Y-quenchers in the torus. These expansion joint bellows were replaced in 1990. The replacement expansion joint bellows were analyzed in accordance with the standards of the Expansion Joint Manufacturers Association, Inc. as modified to the requirements of ASME Section III, Subsection NC-3649, for movements and cyclic requirements based on a specified 40-year life. The replacement ERV expansion joint bellows were designed for at least 16,000 primary design condition cycles. The design condition is associated with the movement of the main steam piping during warm-up (startup and shutdown transients).

Two hundred and eighteen startup and 216 shutdown transient occurrences are projected for 80 years. These projections are significantly less than the 16,000 cycle occurrences specified for the design life of the ERV bellows.

Therefore, the transient conditions and associated cycle occurrences that were assumed for the design life of the ERV bellows remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.8 Spent Fuel Pool Liner Fatigue Analysis

The spent fuel pool (SFP) storage capacity was expanded in 1999, and new fuel storage racks were installed. Although not required by ASME Section III, the portion

of the SFP liner which supports the new fuel storage racks was evaluated for fatigue using the guidance of ASME Section III. The fatigue evaluation assumed one safe shutdown earthquake (SSE) and five operating basis earthquake (OBE) transients. The resulting fatigue evaluation calculated a cumulative usage factor value of 0.0092.

One OBE transient is projected for 80 years. Therefore, the transients and transient occurrences that were assumed in the original analysis remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.9 Spent Fuel Pool Storage Rack Fatigue Analysis

The spent fuel pool (SFP) storage capacity was expanded in 1999, and new fuel storage racks were installed. Although not required by ASME Section III, the new fuel storage racks were evaluated for fatigue using the guidance of ASME Section III. The fatigue evaluation assumed one safe shutdown earthquake (SSE) and five operating basis earthquake (OBE) transients. The resulting fatigue evaluation calculated a cumulative usage factor value of 0.564.

One OBE transient is projected for 80 years. Therefore, the transients and transient occurrences that were assumed in the original analysis remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7 Other Plant-Specific Time-Limited Aging Analyses

A.4.7.1 Reactor Vessel and Reactor Vessel Head Flaw Evaluations

A.4.7.1.1 Reactor Vessel Flaw Evaluations

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for NMP1 in which unacceptable indications in the reactor pressure vessel (RPV) shell were identified in 1999 by ultrasonic testing in axial weld RVWD-140 and shell-to-flange circumferential weld RVWD-099. Structural evaluations of these flaws were performed in accordance with ASME Section XI, Subsection IWB-3600.

A flaw analysis was performed for the RPV flaws using the previous analysis methodology considering fatigue crack growth and irradiation embrittlement through the end of the subsequent period of extended operation. The projected 67 effective full power year fluence values were used to determine the effects of embrittlement for RVWD-140, demonstrating that the fracture toughness of the indications remain bounded by the previous evaluation. The analysis analytically grew the indications considering 882 cycles of operation utilizing the prior methodology. The evaluation concluded that the indications with flaw growth meet the acceptance criteria of the established flaw handbook, and are therefore acceptable for continued operation through the end of the subsequent period of extended operation.

Examinations of the RPV welds, performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program, provide additional confirmation that the flaws remain within the bounding flaw dimensions. Therefore, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program will manage the associated effects of cracking on the reactor

pressure vessel welds through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.1.2 Reactor Vessel Closure Head Flaw Evaluations

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for NMP1 in which an unacceptable subsurface flaw indication in the reactor pressure vessel (RPV) closure head was identified in 2003 by ultrasonic testing (UT) in closure head meridional weld RVWD-005. In addition, an unacceptable indication between the RPV head flange and closure head was identified in 2011 by UT in circumferential weld RVWD-001. Structural evaluations of these flaws were performed in accordance with ASME Section XI, Subsection IWB-3600.

A flaw analysis was performed for the RPV closure head flaws considering fatigue crack growth through the end of the subsequent period of extended operation. The analysis was performed utilizing the previous methodology and flaw handbook. The projected 67 effective full power year fluence values were used to confirm that at the axial height of the RPV closure head welds, the 80-year projected fluence values are below the threshold for fracture toughness property changes and are therefore not applicable to the RPV closure head indications. The evaluation analytically grew the indications of RVWD-001 considering 841 operational cycles utilizing the prior methodology. As the indication of RVWD-005 was identified in 2003, and the flaw handbook utilized is valid for 40 additional years of operation from the finding, an additional 36 operational cycles were applied for the six additional years of operation to extend the results of the flaw handbook through the subsequent period of extended operation. The evaluation concluded that the final crack sizes for RVWD-001 and RVWD-005 at the end of the subsequent period of extended operation are both less than the allowable flaw sizes. Therefore, the RPV closure head flaws remain acceptable for continued operation through the end of the subsequent period of extended operation.

Examinations of the RPV closure head welds performed under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program, provide additional confirmation that the flaws remain within the bounding flaw dimensions. Therefore, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program will manage the associated effects of cracking on the reactor pressure vessel closure head welds through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.2 Reactor Water Cleanup System Weld Overlay Fatigue Flaw Growth Evaluations

Nine Mile Point Nuclear Station's first license renewal application documented a TLAA for NMP1 in which fatigue crack growth analyses had been performed for two weld overlays (Weld 33-FW-22 and Weld 33-FW-23A) in the reactor water cleanup (RWCU) system. Weld 33-FW-22 was repaired in 1997 due to a through-wall pinhole leak by performing a weld overlay and is classified as intergranular stress corrosion cracking (IGSCC) Category E1. Weld 33-FW-23A was repaired in 2004 due to a through-wall leak by performing a weld overlay and is classified as IGSCC Category E1.

Fatigue crack growth analyses were performed in accordance with ASME Section XI, Appendix C, with the crack propagating into the overlay from the hypothetical 1/16-

inch deep crack. The analysis for weld 33-FW-22 was performed in 1997 and assumed 154 startup/shutdown occurrences. The analysis for weld 33-FW-23A was performed in 2005 and assumed 168 startup/shutdown occurrences. Weld 33-FW-22 is projected to experience 112 startup/shutdown transient occurrences at the end of the subsequent period of extended operation (SPEO), and weld 33-FW-23A is projected to experience 74 startup/shutdown transient occurrences at the end of the SPEO. These values are both below the postulated 154 and 168 startup/shutdown transients assumed in the original fatigue crack growth analyses for 33-FW-22 and 33-FW-23A, respectively.

However, to ensure continued acceptability, the weld overlays are subject to augmented inspection under the BWR Stress Corrosion Cracking (A.2.1.5) program. The BWR Stress Corrosion Cracking (A.2.1.5) program will continue to perform inspections of the welds periodically through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.3 Generic Letter 81-11, “Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking””

NUREG-0619 was issued by the NRC per NRC Generic Letter 81-11 in February 1981 because of observed cracking on the inside surfaces of boiling water reactor (BWR) feedwater (FW) nozzles at the blend radius and bore. The causes included: on-off feedwater flow control at low power, high clad thermal stresses, and leakage between the safe-end and the thermal sleeve. In the original BWR designs like NMP1, the thermal sleeve was loosely fit into the nozzle bore. The leakage caused rapid thermal cycling, on the order of a few cycles per second, driven by convective instability in the mixing region. Such cracking was observed in the NMP1 feedwater nozzles early in the unit's life prior to 1980.

Starting in 1977, the following NUREG-0619 recommended modifications were implemented at NMP1 to reduce or eliminate feedwater nozzle rapid thermal cycling fatigue cracking mechanism: (a) removal of cladding from the nozzle bore and blend radii, (b) improved thermal sleeve and sparger design, (c) reactor water cleanup return line rerouted to the feedwater line, and (d) improved feedwater flow control. The control rod drive return line (CRDRL) nozzle was modified by replacing the safe end with improved intergranular stress corrosion cracking (IGSCC) resistant material and thermal sleeve so that examinations could be performed during the 1977 outage. The NMP1 welded-in-place CRDRL nozzle thermal sleeve design makes the nozzle less susceptible to rapid thermal fatigue cracking than the original designs implemented at other BWRs.

In addition to the recommended modifications, NUREG-0619 also established inspection intervals and methods. The growth of an assumed existing fatigue crack was used to define enhanced inspection intervals. A series of calculations including stress, fatigue usage, and crack growth of an assumed flaw were performed to determine conservative inspection intervals for the FW nozzles.

In 1998, NMP1 revised its commitment for FW nozzle inspections to be in accordance with the recommendations in the BWROG Report, which provided technical justification for alternate BWR FW nozzle inspection requirements based

on fracture mechanics evaluations performed to date, actual inspection experience, and advances in ultrasonic inspection techniques since 1980. These BWROG evaluations relied on fracture mechanics analyses that modeled the flaws from a small crack, detectable by UT, to large detectable cracks which were still significantly less than the size for which a failure may be expected.

The BWROG Report does not address CRDRL nozzle inspections and therefore NMP1 reaffirmed its commitment to perform periodic inspections of the NMP1 CRDRL nozzle in accordance with NUREG-0619, as amended by previous UT inspection commitments. These evaluations and proposed alternatives were accepted by the NRC in February 1999 as an acceptable alternative to the inspection guidelines in NUREG-0619.

The NMPNS first license renewal application credited enhanced inspections in accordance with the Inservice Inspection (ISI) program for the management of rapid thermal cycling fatigue cracking in the FW and CRDRL nozzles. The inspections would, in effect, provide confirmation that cracking due to rapid thermal cycling fatigue or low cycle fatigue is not occurring. In addition, the NMP1 first license renewal credited the Fatigue Monitoring (A.3.1.1) program for aging management of low cycle fatigue in the FW nozzles.

The implementation of the modifications and improvements to plant operations were effective in preventing additional high cycle fatigue cracking at NMP1. However, to ensure continued acceptability, NMP1 has committed to maintain the inspection of the FW and CRDRL nozzles within the ISI Program.

The effects of aging on the intended functions will be managed by the inspections performed as part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program. This aging management program is consistent with ASME Section XI and will be used to confirm the continued acceptability of the FW and CRDRL nozzles. In addition, the Fatigue Monitoring (A.3.1.1) program is credited with managing the FW and CRDRL nozzles low cycle fatigue through the subsequent period of extended operation in accordance with 10 CFR 54.21 (c)(1)(iii).

A.4.7.4 Valve Fatigue Analyses

A.4.7.4.1 Feedwater Isolation Check Valves Fatigue Analysis

The NMP1 Feedwater Isolation Check Valves (CKV-31-01R and CKV-31-02R) were replaced in 2005 and designed in accordance with the ASME Section III, Division 1, Subsection NC, 1986 Edition. These check valves are ASME Class 2 components, and while a fatigue analysis is not required, a fatigue evaluation was provided for the replaced feedwater check valves using the guidance of the ASME code.

The fatigue evaluation in the analysis assumed a total of 760 operating cycles consisting of 240 cycles of heatup, 229 cycles of cooldown, 10 cycles of emergency cooldown, 1 cycle of blowdown, and 280 scram cycles. In addition, five operating basis earthquake (OBE) and one safe shutdown earthquake (SSE) events, each comprised of 10 cycles were assumed, resulting in a total of 60 cycles. Therefore, the analysis considered a total of 820 cycles over a 40-year life. The resulting fatigue evaluation calculated a cumulative usage factor of 0.68.

Total 80-year transient projections for heatup, cooldown, emergency cooldown, safety relief valve (SRV) blowdown, scram, and OBE are all less than the assumed occurrences for these transients, and as the feedwater check valves were replaced in 2005, the projected number of transients at the end of the subsequent period of extended operation (SPEO) is much lower. NMP1 has not experienced an SSE transient, and the assumed SSE transient is bounding during the SPEO. Therefore, the transients and transient occurrences that were assumed in the original analysis remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.4.2 Emergency Condenser Steam Isolation Valves Fatigue Analysis

The NMP1 emergency condenser steam isolation valves (ECIV's) (IV-39-07R through IV-39-10R) were replaced in 1983 and designed in accordance with the ASME Section III, Summer 1980 Edition with Addenda up to and including Summer 1982. These ECIV's are not ASME Class 1 components, and while a fatigue analysis is not required, a fatigue evaluation was provided for the replaced ECIV's using the guidance of the ASME code.

The design analysis evaluated fatigue in accordance with ASME Section III, Subsection NB-3500, "Valve Design," and demonstrated compliance with the acceptance criteria for normal duty valve fatigue requirements in accordance with NB-3545.3, by determining an allowable number of $1.0\text{E}+6$ cycles, against an applied 2,000 cycles of startup and shutdown transients. In addition, the design analysis demonstrated fatigue acceptance in accordance with ASME Section III, Subsection NB-3553, based upon an applied 10 cycles of "quick stop" corresponding to an instantaneous 475 degrees F heatup and 475 degrees F cooldown.

Emergency condenser steam isolation valves IV-39-07R through IV-39-10R are normally on standby, with the isolation valves on the steam supply lines open, and would be expected to experience thermal cycles along with the reactor (startup and shutdown transients). In addition, it is also assumed that the ECIV's will experience normal duty operation cycles associated with emergency condenser system specific transients.

Total 80-year transient projections for normal startup, normal shutdown, and all emergency condenser actuations summed together is 860 cycles, which is less than 2,000 cycles defined in the original analysis.

In addition, to demonstrate acceptance in accordance with the requirements of ASME Section III, NB-3553, an applied 10 cycles of "quick stop" corresponding to an instantaneous 475 degrees F heatup and 475 degrees F cooldown were applied to the ECIVs. Experiencing 10 cycles of this transient is not credible, as the transient is defined to occur instantaneously. The only way a step-change in ECIV fluid temperature of 475 degrees F is possible would be during a loss-of-cooling accident (LOCA). NMP1 has not experienced a LOCA, therefore exceeding 10 cycles of this transient during the subsequent period of extended operation is not credible.

Therefore, the transients and transient occurrences that were assumed in the original analysis remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.4.3 Emergency Condenser Condensate Return Check Valves Fatigue Analysis

The NMP1 emergency condenser condensate return check valves (CKV-39-03 and CKV-39-04) were replaced in 1995 and designed in accordance with the ASME Section III, 1986 Edition. The internals of CKV-39-04 were replaced in 2003 and were designed in accordance with ASME Section III, Subsection NB, 1986 Edition. These check valves are not ASME Class 1 components, and while a fatigue analysis is not required, fatigue analyses were provided for the replaced check valves using the guidance of the ASME code.

The design analyses for both valves evaluated fatigue in accordance with ASME Section III, 1986, Subsection NB-3500, "Valve Design," and demonstrated the acceptance criteria for normal duty valve fatigue requirements in accordance with NB-3545.3, by determining an allowable number of $1.0\text{E}+6$ cycles, against an applied 2,000 cycles of startup and shutdown transients.

The analyses both considered an applied 2,000 cycles of normal duty operational cycles (100 degree F/hr change rate) corresponding to startup and shutdown transients. Check valves CKV-39-03 and CKV-39-04 would experience these thermal cycles along with the reactor (startup and shutdown transients) and it is also assumed that the check valves will experience normal duty operation cycles associated with the emergency condenser system specific transients. Total 80-year transient projections for normal startup, normal shutdown, and all emergency condenser actuations summed together is 860 cycles, which is less than 2,000 cycles defined in the original analysis.

Therefore, the transients and transient occurrences that were assumed in the original analysis remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.5 Electromatic Relief Valve Vacuum Breaker Valve Fatigue Analysis

There are two 10-inch vacuum breaker swing check valves (CKV-66-25 through CKV-66-36) installed on each of the six electromatic relief valve (ERV) discharge lines into the torus. After CKV-66-26 failed during the NMP1 restart of Fall 2000, each of the twelve 10-inch ERV vacuum breakers were modified to prevent failures of the disk hinge arms during valve actuation. The vacuum breaker valves are ASME Class 3 components, and while an ASME Code fatigue analysis is not required, fatigue evaluations using the guidance of the ASME code were provided for the modified vacuum breaker valve subcomponents that are affected by cyclic impact loads to assess the adequacy of the design.

The fatigue analyses of the modified ERV vacuum breaker valves each assumed 7,000 cycles of "full ERV discharge during normal operation", and 1,000,000 cycles of "leaking ERV at low reactor pressure." The resulting fatigue analyses applied these transients to each of the vacuum breaker valve pressure boundary and internal components and determined a maximum cumulative usage factor (CUF) of 0.07.

The total 80-year transient projections for actuations of any individual ERV is 94 and the total number for all ERVs combined is 492. Therefore, adequate margin remains in the 7,000 ERV actuations that were assumed in the analyses. Fatigue due to the postulated "leaking ERV at low reactor pressure" transient is negligible as the

number of cycle occurrences postulated is beyond the endurance limit of the ASME fatigue curves. Therefore, the transients and transient occurrences that were assumed in the original analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.6 Core Spray System Weld Fatigue Flaw Growth Evaluation

A fatigue flaw growth analysis was performed in 1999 to evaluate the acceptability of nondestructive examination (NDE) indications found in weld number 81-WD-059 in the core spray pump suction line from the condensate storage tank valves at VLV-81-37 and VLV-81-38. The NDE indications were determined to have originated during the original welding process. Since the indications in weld number 81-WD-059 did not meet the screening criteria of ASME, Subsection IWB-3500, a fatigue flaw growth analysis was performed using the guidance of ASME Section XI, 1995 Edition, IWB-3600 and Appendix H criteria.

The analysis assumed a total of 200 cycles comprised of 100 seismic loading cycles and 100 pressure cycles due to testing of the core spray line during refueling outages.

One operating basis earthquake (OBE) is projected for 80 years. NMP1 has not experienced an OBE, and the assumed 100 seismic cycles are bounding during the subsequent period of extended operation.

Valves VLV-81-37 and VLV-81-38 are locked closed during normal plant operation. This core spray system line is used only for testing one core spray pump set in each loop with suction from the condensate transfer system during each refueling outage (RFO). Prior to entering the subsequent period of extended operation (SPEO), NMP1 will have performed 30 RFO's. The NMP1 reactor operates on a 24-month refueling cycle, therefore 10 more RFO's or pressurization cycles for testing of the core spray line analyzed can be expected at the end of the SPEO, for a total of 40 pressurization cycles over 80 years. Therefore, the 100 pressure cycles assumed in the flaw analysis remain bounding for 80 years.

Therefore, adequate margin remains in the 200 cycles assumed in the evaluation of weld number WD-81-059, and the flaw growth evaluation remains valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.7 Control Rod Drive Bottom Head Penetrations Fracture Mechanics Analysis

Nine Mile Point Nuclear Station, Unit 1 has control rod drive (CRD) reactor pressure vessel (RPV) bottom head penetrations that have leaked due to intergranular stress corrosion cracking (IGSCC) in the furnace sensitized stainless steel stub tubes. For CRD penetrations that have leaked, a roll-expansion repair method to eliminate the leakage has been implemented since 1984. As part of the first license renewal application, NMP1 committed to implement a zero leakage roll repair method for leaking CRD penetrations utilizing ASME Section XI, Code Case N-730, "Roll-Expansion of Class 1 Control Rod Drive (CRD) Bottom Head Penetrations in BWRs," as accepted by the NRC safety evaluation report. To demonstrate compliance with the technical requirements of code case N-730, a comparative fracture mechanics evaluation was performed. The evaluation compared key parameters of the NMP1 CRD penetrations against the parameters provided in the generic fracture mechanics

evaluation contained in the technical-basis document for Code Case N-730: BWRVIP-146NP, Revision 1, "BWR Vessel and Internals Project, Technical Basis for ASME Code Case N-730, "Roll-Expansion of Class 1 Control Rod Drive Bottom Head Penetrations in BWRs".

The NMP1 comparative analysis demonstrated that the NMP1 CRD bottom head penetrations are bounded by the generic analysis and concluded that sufficient fracture margins exist for a 60-year plant life, as accepted by the NRC.

The CRD bottom head penetration fracture mechanic comparative analysis has been reevaluated for the subsequent period of extended operation (SPEO). The fracture mechanics parameters in the comparative fracture mechanics evaluation remain acceptable as the NMP1 fracture margin remains higher than the value in the generic analysis and the 80-year total number of transient occurrences remain less than the number of cycles postulated in the generic assessment. Therefore, the parameters of the NMP1 CRD bottom head penetration fracture mechanics comparative analysis remain bounded by those of the generic fracture mechanics analysis for the SPEO.

The CRD bottom head penetrations fracture mechanics analysis has been successfully projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.7.8 Crane Cyclic Loading Analyses

The NMP1 reactor building crane, turbine building crane, and screenhouse building crane meet the intent of Crane Manufacturer's Association of America (CMAA) Specification 70.

Per CMAA Specification 70, these cranes are considered a "Class A" crane experiencing "irregular occasional use followed by long idle periods." For this designation, the specification allows between 20,000 and 100,000 cycles at rated load. Load cycles that lift less than 50 percent of the crane design capacity result in minimal fatigue of the crane. Therefore, only load cycles that lift 50 percent or more were evaluated for the subsequent license renewal application.

For the reactor building crane, the number of heavy lift cycles projected for 80 years of operation is 3,160 cycles which is approximately 15.8 percent of the 20,000-cycle conservative threshold. For the turbine building crane, the number of heavy lift cycles projected for 80 years of operation is 716 cycles which is approximately 3.6 percent of the 20,000-cycle conservative threshold. For the screenhouse building crane, the number of heavy lift cycles projected for 80 years of operation is 1,380 cycles which is approximately 6.9 percent of the 20,000-cycle conservative threshold.

Therefore, the fatigue analysis for these cranes remains valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.9 Core Shroud Tie Rod X-750 Inconel Component Service Life

In 1995, NMP1 installed four core shroud tie-rod assemblies (tie-rods) as a repair in response to cracks that were identified on the core shroud horizontal welds. These assemblies included subcomponents made of X-750 Inconel. In 2007, the top

portion of all four tie-rods, including the “top nuts” which are fabricated from X-750 material were replaced after the potential for high peak stresses in the original shroud stabilizer upper support design was discovered.

In January 2007, General Electric (GE) Energy issued a Safety Information Communication Letter to applicable stations related to the potential for intergranular stress corrosion cracking (IGSCC) cracking of core shroud repair tie-rod subcomponents fabricated from X-750 Inconel. The letter concluded that threaded subcomponents with calculated stresses less than 78 percent of yield strength have a 40-year service life. This letter did not document a service life for threaded X-750 components beyond 40 years. For nonthreaded components, BWRVIP-84, Revision 2-A requires the sustained stress level under normal operating conditions to not exceed 70 percent of the ASME Code or CMTR minimum yield strength of the material at the intended operating temperature for a 40-year design. BWRVIP-84, Revision 2-A, “BWR Vessel and Internals Project: Guidelines for Selection and Use of Materials for Repairs to BWR Internal Components,” does not document an allowable stress ratio for a design life beyond 40 years.

In 2007, GE provided NMP1 with additional proprietary reports which documented the calculated stresses for all NMP1 tie-rod subcomponents fabricated from X-750 material. Three threaded X-750 subcomponent types exceeded the 78 percent threshold, and one non-threaded X-750 subcomponent exceeded the 70 percent threshold.

In addition, in 2007, GE provided NMP1 with proprietary reports which justified a 40-year service life for threaded and non-threaded X-750 subcomponents in which the calculated stress exceeded 78 percent and 70 percent of yield stress, respectively.

The NMP1 BWR Vessel Internals (A.2.1.7) program specifies that materials used for repairs or replacements meet the guidelines of BWRVIP-84, Revision 2-A, as modified by BWRVIP Letter 2011-011, “Guidance for Evaluating Repair Hardware with X-750 Components.”

As a result, the NMP1 BWR Vessel Internals (A.2.1.7) program will be enhanced to develop a justification for a service life through the subsequent period of extended operation, consistent with BWRVIP-94, Revision 4, which may include supplemental inspections, inspection frequencies, and technical evaluations to validate that tie-rod X-750 subcomponents can perform their intended function through the subsequent period of extended operation. This enhancement will be implemented no later than six months prior to the subsequent period of extended operation. Therefore, this TLAA will be managed by the NMP1 BWR Vessel Internals (A.2.1.7) program through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.5 Subsequent License Renewal Commitment List

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing program is credited.	Ongoing	Section A.2.1.1
2	Water Chemistry	Existing program is credited.	Ongoing	Section A.2.1.2
3	Reactor Head Closure Stud Bolting	Existing program is credited.	Ongoing	Section A.2.1.3
4	BWR Vessel ID Attachment Welds	Existing program is credited.	Ongoing	Section A.2.1.4
5	BWR Stress Corrosion Cracking	Existing program is credited.	Ongoing	Section A.2.1.5
6	BWR Penetrations	Existing program is credited.	Ongoing	Section A.2.1.6
7	BWR Vessel Internals	BWR Vessel Internals is an existing program that will be enhanced to: 1. Develop a justification for operation of the top guide through the subsequent period of extended operation by means of a flaw evaluation, consistent with BWRVIP-94, Revision 4; BWRVIP-183-A; BWRVIP-100, Revision 2-A; BWRVIP-14-A; and EPRI Letter 2025-057; as applicable, and develop the necessary inspections and inspection frequencies to validate that the top guide can perform its intended function through the subsequent period of extended operation. Revise procedures governing the top guide inspections to reflect the flaw evaluation, necessary inspections, and inspection frequencies. 2. Develop a justification for the service life of the core shroud tie-rod X-750 subcomponents through the subsequent period of extended operation, consistent with BWRVIP-94, Revision 4, which may include supplemental inspections, inspection frequencies, and technical evaluations to validate that	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.7

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	BWR Vessel Internals (continued)	the core shroud tie-rod X-750 subcomponents can perform their intended function through the subsequent period of extended operation.		
8	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide reasonable assurance that the intended functions of the reactor coolant pressure boundary CASS components (i.e., piping components, pump casings, and covers) with the potential for significant thermal aging embrittlement will be maintained.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.8
9	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion is an existing program that will be enhanced to: 1. Reassess infrequently used piping systems excluded from the scope of the program to ensure adequate bases exist to justify this exclusion for periods of extended operation beyond 60 years. 2. Reassess piping systems that were susceptible to cavitation but had lines excluded from the erosion program based on the 2 percent exclusion criterion to determine if the lines should be included in the erosion program based on the less than 100 hours of operation per year criteria.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.9
10	Bolting Integrity	Bolting Integrity is an existing program that will be enhanced to: 1. Perform periodic visual inspections of a representative sample of bolting for bolted joints where leakage is difficult to detect. A representative sample will consist of 20 percent of the population or up to a maximum of 25 bolts and nuts for each material and environment population, whichever is less, and inspections will be performed during each 10-year period of the subsequent period of extended operation. Inspections will be performed of bolting utilized in joints that are submerged, in systems that are not normally pressurized, and in systems containing air or gas. If the minimum sample size is not achieved during a 10-year period, then alternative inspections may be performed. For submerged bolting exposed to treated or raw water, alternative inspections may include (1) diver inspections or (2) remote video inspections. For systems not normally pressurized, alternative inspections may include (1) visual inspection during system tests when the system is pressurized or (2) visual inspection for signs of leakage from when the system was under testing. For systems containing air/gas, alternative inspections may include (1) visual inspection for discoloration when leakage	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.10

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Bolting Integrity (continued)	from inside the piping system would discolor the external surfaces of the component; (2) monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary; (3) soap bubble testing on the external mating surface of the bolted component; or (4) thermography, when the temperature of the process fluid is higher than ambient conditions around the component. These inspections will verify that no age-related degradation such as cracking, loss of material, or loss of preload are occurring. 2. Revise procedures governing the direct visual examination of bolted joints to include inspection parameters such as lighting, distance, and offset. Cameras and video equipment may be used to supplement these inspections. 3. Revise engineering procedures to require results of sampling-based inspections to 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. 4. Ensure no fewer than two additional inspections for each sample-based inspection that does not meet acceptance criteria, or 10 percent of the total bolt population of each applicable material, environment, and aging effect combination, whichever is less. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be performed to determine the further extent of inspections. These additional inspections will be completed within the inspection interval in which the original sample-based inspections are conducted.		
11	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System is an existing program that will be enhanced to: 1. Perform a minimum of 10 inspections for recurring internal corrosion in the raw water systems, including water-based fire systems, every 24 months until the rate of recurring internal corrosion occurrence no longer meets the criteria for recurring internal corrosion as defined in SLRA Section 3.3.2.2.7. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include: (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.11

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Open-Cycle Cooling Water System (continued)	thickness to determine the acceptability of the component for continued use; and (3) a determination of re-inspection interval. - Revise the raw water piping inspection program to require that any internal visual inspections performed on in scope concrete piping for subsequent license renewal, parameters monitored or inspected, acceptance criteria and qualifications of inspectors be in accordance with ACI 349.3R and ACI 201.R1. - Perform cleaning, flushing and inspections on the cooling coils for two of the reactor building area coolers and two of the turbine building area coolers during each 10-year period. Coils are to be internally cleaned, flushed, then inspected. Inspection method to be capable of detecting wall thinning or loss of material on the internal raw water side of the tubes. - Perform quarterly monitoring of the service water and containment spray raw water pump motor bearing temperatures. The results will be trended to establish a baseline, and indications of abnormal temperature trends will be investigated in accordance with the corrective action program. - Perform cleaning, flushing and inspection of the service water and containment spray raw water pump motor cooling tubes during maintenance on the motors on a frequency not to exceed 10 years.		
12	Closed Treated Water Systems	Closed Treated Water Systems is an existing program that will be enhanced to: Perform condition monitoring including sample-based periodic inspections using techniques (visual, surface, or volumetric) capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects in each 10-year period during the subsequent period of extended operation. If degradation is identified, then the rate of degradation will be projected until the next scheduled inspection. Additional sample-based inspections will be performed if unacceptable aging is identified. If those inspections identify unacceptable aging, then the corrective action program will be used to determine the extent of condition and extent of cause to determine the extent of further inspections.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.12

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
13	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 is an existing program that will be enhanced to: 1. Provide additional procedural guidance to include inspection of bolting for cracking and loss of material.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.13
14	Compressed Air Monitoring	Compressed Air Monitoring is an existing program that will be enhanced to: 1. Revise program implementation and criteria to be in accordance with ANSI/ISA-7.0.01-1996 guidelines. The existing program is based on ANSI/ISA-7.3.1975 guidelines, and the enhancement will bring the existing program in line with current standards and vendor recommendations without any impact on the program's ability to maintain component intended functions during the subsequent period of extended operation. 2. Revise program implementation and criteria to be in accordance with ASME OM-2012 Division 2, Part 28 guidelines. The existing program is based on ASME OM-1998, Part 17 guidelines, and the enhancement will bring the existing program in line with current standards and vendor recommendations without any impact on the program's ability to maintain component intended functions during the subsequent period of extended operation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.14
15	Fire Protection	Fire Protection is an existing program that will be enhanced to: 1. Perform visual inspections of combustible liquid spill retaining curbs. Combustible liquid spill retaining curbs will be inspected for signs of age-related degradation that could affect the intended function of the component. Curbs will be inspected for signs of cracking, spalling, corrosion, or loss of material that could impede the leak tight functionality of the curb. 2. Perform visual inspections of fire doors for age-related degradation. 3. Visually inspect fire damper housings for cracking. 4. Perform an inspection of not less than 10 percent of each type of seal during each inspection interval.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.15
16	Fire Water System	Fire Water System is an existing program that will be enhanced to: 1. Perform a one-time volumetric wall thickness inspection test of a representative sample of sections of pipe that are periodically subjected to	Program will be enhanced no later than six months prior to the	Section A.2.1.16

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Fire Water System (continued)	flow but are normally dry. The representative sample will be based on the population of system piping that is periodically subject to flow but is normally dry. The one-time volumetric wall thickness inspection test activity will include criteria for selection of inspection locations, acceptance criteria, and will specify the need for follow-up examinations based on inspection results. 2. Revise the hydrant flushing procedure to require hydrants be flushed for at least a full minute. 3. Perform system mainline strainer inspections after system operation or testing. 4. Perform, on a five-year frequency, internal visual inspections of every other in scope suppression system. These inspections will include nozzle inspections when performed on deluge systems. The systems not inspected in the first five-year interval will be inspected in the second five-year interval. In dry pipe systems and pre-action systems, the sprinkler removed for inspection shall be from the most remote branch line from the source of water that is not equipped with the inspector's test valve. Tubercules or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC). If the presence of foreign organic and/or inorganic material is found in any system in a building during the five-year internal inspection of piping, all systems shall be assessed. If the presence of sufficient foreign organic and/or inorganic material is found to obstruct pipe or sprinklers, an obstruction investigation will be conducted as described in Section 14.3 of NFPA 25. Alternatively, nondestructive examinations capable of ensuring flow blockage in piping and nozzles will not occur will be performed. The population of suppression systems eligible for inspection consist of the in scope wet pipe sprinkler systems, dry-pipe systems, preaction systems, and deluge systems that are not functionally tested. 5. Perform two additional fire water system flow tests within the test interval (frequency) for each failed test. 6. Perform a system mainline strainer inspection and cleaning after system flow exceeding that of a nominal two-inch orifice. 7. Perform annual functional tests of the: 1) turbine building west wall water curtain, 2) turbine building south wall water curtain, and 3) turbine building south and east control building wall exposure above administration building roof deluge systems.	subsequent period of extended operation. One-time inspections will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.	

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Fire Water System (continued)	8. Perform annual inspections of the two charcoal deluge system strainers and the strainer to the interior spray system manifold.		
17	Not Used			
18	Fuel Oil Chemistry	Fuel Oil Chemistry is an existing program that will be enhanced to: 1. Perform periodic internal inspection of the emergency diesel generator fuel oil day tanks and diesel driven fire pump fuel oil day tank at least once during each 10-year period starting 10 years prior to the subsequent period of extended operation. Each tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, then these diesel fuel tanks will be volumetrically inspected. 2. Perform periodic (quarterly) sampling, analysis, and trending for water and sediment content, particulate concentration, and the levels of microbiological organisms for the emergency diesel generator fuel oil day tanks and diesel driven fire pump fuel oil day tank. The new sampling activities will include a sampling methodology that includes a representative sample from a low point in the tank which will provide for a more conservative sample than the multilevel sampling techniques described in ASTM D4057. 3. Perform periodic (quarterly) sampling, analysis, and trending for the levels of microbiological organisms for the emergency diesel generator fuel oil storage tanks and the diesel driven fire pump fuel oil storage tank.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.18
19	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance is an existing program that will be enhanced to: 1. Implement BWRVIP-321, Revision 1-A to maintain compliance with 10 CFR 50 Appendix H during the subsequent period of extended operation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.19
20	One-Time Inspection	One-Time Inspection is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (1) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation; (2) the insignificance of an aging effect; and (3) that long-term loss of	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.20

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	One-Time Inspection (continued)	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.	Inspections will be completed within the 10 years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.	
21	Selective Leaching	Selective Leaching is a new condition monitoring program that will monitor components constructed of materials that are susceptible to selective leaching and that are exposed to environments that may result in the occurrence of selective leaching in susceptible materials. Susceptible materials include gray cast iron, malleable iron, ductile iron, and copper alloys containing greater than 15 percent zinc. Copper alloys containing greater than eight percent aluminum are also susceptible to selective leaching; however, there are no components within the scope of license renewal that are constructed of this material at NMP1. The selective leaching program includes one-time inspections for susceptible components exposed to closed cycle cooling water and treated water environments since plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections are conducted for susceptible components exposed to raw water, waste water, and soil (which may include groundwater) environments.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections required to be completed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.21
22	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping aging management 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 nominal pipe size (NPS) 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	Program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections will be completed within the six years prior to the subsequent period of	Section A.2.1.22

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	ASME Code Class 1 Small-Bore Piping (continued)	examination volume of interest. Destructive examination methods may be performed in lieu of volumetric examination. The program examinations are performed to verify that degradation is not occurring and to validate the effectiveness of existing programs and practices, thereby confirming that no additional aging management is required for the subsequent period of extended operation.	extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.	
23	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components is a new condition monitoring program that will manage the loss of material, cracking, hardening or loss of strength of elastomeric and polymeric components, and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic, elastomeric, polymeric, and insulation jacketing (insulation when not jacketed), and cementitious components will be conducted.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.23
24	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new condition monitoring program that will manage loss of material, recurring internal corrosion, and cracking of metallic components, as well as loss of material and hardening or loss of strength in elastomers, and cracking or blistering, loss of material, and hardening or loss of strength in polymers. Reduction of heat transfer and flow blockage will also be managed. This program will consist of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components and other mechanical components.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.24
25	Lubricating Oil Analysis	Lubricating Oil Analysis is an existing program that will be enhanced to: 1. Perform periodic sampling and testing of lubricating oil for moisture and corrosion particles in the liquid poison system pump gearboxes, following industry or vendor recommended practices. Alternatively, test old oil after periodic oil changes for the liquid poison system pump gearboxes based on vendor intervals or station experience. 2. Perform periodic sampling and testing of hydraulic oil for moisture and corrosion particles in the circulating water gates and hoists system hydraulic fluid reservoir, following industry or vendor recommended practices. Alternatively, test old oil after periodic oil changes for the circulating water gates and hoists system hydraulic fluid reservoir based on vendor intervals or station experience.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.25

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
26	Monitoring of Neutron-Absorbing Materials Other than Boraflex	Existing program is credited.	Ongoing	Section A.2.1.26
27	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks is an existing program that will be enhanced to: 1. Perform one direct visual inspection of a 10-linear foot segment of buried carbon steel piping within the scope of license renewal during each 10-year period beginning 10 years prior to the subsequent period of extended operation. The number of inspections will be increased to six 10-linear foot segments of buried carbon steel piping within the scope of license renewal if either of the following criteria are not met for the cathodic protection system protecting the buried steel piping within the scope of license renewal: a. System is maintained operational at least 85 percent of the time for 10 years prior to the subsequent period of extended operation (excluding time periods in which the cathodic protection system is off-line for testing). b. System has provided effective protection for buried steel piping as verified through acceptable annual system testing results 80 percent of the time for 10 years prior to the subsequent period of extended operation. Testing results for cathodic protection systems protecting steel piping is acceptable if instant off potential is -850 mV or more negative, relative to a copper/copper sulfate reference electrode. 2. Perform extent of condition inspections for steel piping as follows: When measured pipe wall thickness, projected to the end of the subsequent period of extended operation, does not meet the minimum pipe wall thickness requirements due to degradation of the external surface, the number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The scope of the follow-up inspections will be determined based on the analysis. Timing of any additional inspections will be based on the severity of the identified degradation and the consequences of leakage or loss of function. Any additional inspections will be performed	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections required to be performed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation, and no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.27

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Buried and Underground Piping and Tanks (continued)	within the same 10-year inspection interval in which the original degradation was identified, or within four years after the end of the 10-year interval if the degradation was identified in the latter half of the 10-year interval. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism or if the piping system or portion of the system is replaced or otherwise mitigated within the same 10-year inspection interval in which the original degradation was identified or within four years after the end of the 10-year interval, if the degradation was identified in the latter half of the 10-year interval. 3. Perform annual system monitoring of the cathodic protection system to ensure effective protection of buried piping with a grace period of up to two months. However, in each calendar year, system monitoring is conducted at least once. 4. Perform direct visual inspection of the in scope underground steel pipe and copper components located in the emergency diesel fuel oil valve pit during each 10-year period beginning 10 years prior to the subsequent period of extended operation. 5. Perform direct visual inspection of the in scope underground fiberglass reinforced plastic and carbon steel piping located in the diesel fire pump tank access vault during each 10-year period beginning 10 years prior to the subsequent period of extended operation. 6. Perform monthly monitoring of the fire system leak rate. The results will be trended to establish a baseline and indications of abnormal leak rate or increasing trends will be investigated in accordance with the corrective action program. If unexplained changes to the fire system leak rate are identified, then a flow test will be performed by the end of the next refueling outage.		
28	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 is a new condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, closed-cycle cooling water, waste water, air, and condensation.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections required to be completed prior to the subsequent period of	Section A.2.1.28

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (continued)		extended operation will be completed within the 10 years prior to the subsequent period of extended operation, and no later than the last refueling outage prior to the subsequent period of extended operation.	
29	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE is an existing program that will be enhanced to: 1. Perform a one-time supplemental surface or enhanced visual examination (i.e., EVT-1 exam) on accessible portions of a representative sample (i.e., 20 percent of population) of high-temperature mechanical drywell penetrations subject to cyclic loading or stress corrosion cracking. If cracking is identified as a result of these inspections, additional inspections will be conducted to increment the sample size by one additional penetration at a time from the uninspected population until cracking is no longer detected. The corrective action program will be used to determine the extent of further inspections, if necessary. 2. Implement a one-time supplemental volumetric examination of the containment metal shell surfaces that are inaccessible from one side, if triggered by plant-specific operating experience. The trigger for this supplemental examination is plant-specific occurrence or recurrence of containment metal shell corrosion (base metal material loss exceeding 10 percent of nominal plate thickness over a local area as defined by ASME Section III 1965, Section N-513.3) initiated on the inaccessible side or areas, identified since the date of issuance of the first renewed operating license. For the purposes of this enhancement, a local area is defined as a circular area with a radius defined by one-half of the square root of the product of the containment metal shell diameter times the containment metal shell thickness at the location in question. This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly selected and focused areas most likely to experience degradation based on plant-specific operating experience and/or other relevant considerations such as environment. The sample size, locations, and any needed scope	Program will be enhanced no later than six months prior to the subsequent period of extended operation. The one-time supplemental surface or enhanced visual examination will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation. If required, the one-time supplemental volumetric examination will be performed in accordance with the schedule identified in the enhancement.	Section A.2.1.29

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	ASME Section XI, Subsection IWE (continued)	expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically with 95 percent confidence that 95 percent of the accessible portion of the containment metal shell is not experiencing corrosion degradation with greater than 10 percent loss of nominal thickness. If required, the supplemental volumetric examinations will be completed within two refueling outages of identification of the triggering containment metal shell corrosion or sooner, as determined by the corrective action program based on the severity of the identified degradation. 3. Provide guidance for 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 consistent with EPRI NP-5067 and TR-104213. Also, provide guidance for storage, lubricant selection, and bolting and coating material selection consistent with Section 2 of Research Council on Structural Connections (RCSC) publication "Specification for Structural Joints Using High-Strength Bolts."		
30	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF is an existing program that will be enhanced to: 1. Perform periodic evaluations of the acceptability of inaccessible areas of supports (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe), when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas of supports. Perform these evaluations once every 10 years during the subsequent period of extended operation. 2. Perform a one-time inspection of an additional five percent of the currently inspected sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. The one-time inspection will be conducted within five years prior to entering the subsequent period of extended operation. The additional supports will be selected from the remaining population of IWF piping supports not already included in the current inspection sample. The expanded sample locations will be selected to include components that are more susceptible to age-related degradation (i.e., based on factors such as time in service, material, and aggressiveness of the environment) than those not in the sample. 3. Revise procedures to require volumetric examination of high-strength bolting (actual measured yield strength greater than or equal to 150 ksi) in sizes	Program will be enhanced no later than six months prior to the subsequent period of extended operation. One-time inspections will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.30

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	ASME Section XI, Subsection IWF (continued)	greater than 1-inch nominal diameter (including ASTM A490 and equivalent ASTM F2280), if additional high-strength bolting is installed. The examination shall be comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 and performed at least once per 10-year interval to detect cracking, in addition to the VT-3 examination required by ASME Section XI. 4. Provide guidance, regarding the selection of supports to be examined in subsequent inspection intervals, when a support that is acceptable for continued service as defined in IWF-3400, is restored in accordance with the corrective action program. The enhanced guidance will ensure that future inspection populations are increased or modified to include another support, of the same type and function, that has not been restored to correct the observed condition. The purpose of increasing or modifying the sample size is to assure that the support population continues to be representative of the remaining population of supports that were not corrected. 5. Perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of a 20 percent representative sample of high-strength bolts (defined as bolts with the same material and environment combination), on a 10-year frequency during the subsequent period of extended operation. The sample shall include the bolting that is most susceptible to age-related degradation (i.e., based on time in service, aggressive environment). If the volumetric examination of these bolts reveals conditions that do not meet acceptance criteria, then the results will be entered into the corrective action program and the inspection will be expanded to include additional high-strength bolts.		
31	10 CFR Part 50, Appendix J	Existing program is credited.	Ongoing	Section A.2.1.31
32	Masonry Walls	Masonry Walls is an existing program that will be enhanced to: 1. Perform masonry wall periodic inspections on a frequency not to exceed five years except for the normally inaccessible areas due to high radiation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.32

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
33	Structures Monitoring	Structures Monitoring is an existing program that will be enhanced to: 1. Include the following structures within the scope of the program: a. Administration building (Original) b. Administration building extension c. Emergency diesel generator fuel oil storage tank foundation d. Emergency diesel generator fuel oil transfer valve pit e. Ring girder for the reactor vessel support skirt 2. Include the following components and commodities within the scope of the program: a. Manholes b. Seismic joint filler c. Sliding surfaces d. Trash racks 3. Implement preventive actions to emphasize proper selection of bolting material and lubricants and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For ASTM A325 or ASTM A490 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection will be in accordance with Section 2 of Research Council for Structural Connection publication "Specification for Structural Joints Using High-Strength Bolts." 4. Clarify procedures to state that evidence of cracking, spalling, scaling, discoloration, and leaching could indicate the presence of increased porosity and permeability due to mechanisms of aggressive chemical attack or leaching of calcium hydroxide and carbonation. 5. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion and for accumulation of debris or dirt. Establish acceptance criteria for sliding surfaces as no significant loss of material due to wear or corrosion and no debris or dirt that could restrict or prevent sliding of the surfaces, as required by design. 6. Expand the program to monitor elastomeric structural sealants, seismic joint fillers, and vibration isolators for cracking, loss of material, and hardening. Supplement visual inspection of elastomeric elements with tactile inspection	Program will be enhanced and initial engineering evaluation will be completed no later than six months prior to the subsequent period of extended operation. Baseline inspections will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.33

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Structures Monitoring (continued)	to detect hardening if the intended function is suspect. Establish acceptance criteria for elastomeric structural sealants, seismic joint fillers, and vibration isolation elements as no loss of material, cracking, or hardening that can lead to loss of intended function. 7. Develop a new implementing procedure or revise an existing implementing procedure to address aging management of inaccessible areas exposed to potentially aggressive groundwater/soil environment that will include the following: a. Monitor raw water and ground water chemistry for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from locations that are representative of the groundwater in contact with structures within the scope of subsequent license renewal. b. Develop engineering evaluations to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or increased frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. c. Develop the initial engineering evaluations prior to the subsequent period of extended operation. Develop follow-up engineering evaluations on an interval not to exceed five years. d. If warranted based on the engineering evaluations, perform focused inspections of representative, accessible (leading indicator) structural elements, or if accessible areas will not be leading indicators for the potential aging mechanisms, excavate and inspect buried concrete elements exposed to potentially aggressive groundwater/soil. e. If degraded concrete is identified, as part of the focused inspections of leading indicators (representative, accessible or exposed inaccessible concrete), enter adverse results that exceed ACI 349.3R-02 tier 2 criteria into the corrective action program, and expose inaccessible concrete so that the extent of the condition can be determined, baseline conditions		

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Structures Monitoring (continued)	documented, and additional actions identified such as repairs, new preventive actions, additional evaluations, and future inspections. 8. Monitor and trend indications of groundwater infiltration or through-concrete leakage. If leakage volumes allow, procedures will be revised to clarify that water chemistry analysis should be considered for parameters including pH, as well as mineral, chloride, sulfate and iron content in the water to assess for potential impact on age-related degradation of concrete or steel reinforcement. This assessment may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. 9. Perform structures monitoring periodic inspections on a frequency not to exceed five years except for the normally inaccessible areas due to high radiation. 10. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R-02 with respect to knowledge of inservice inspection of concrete and visual acuity requirements. 11. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 12. Provide additional guidance on visual indications such as exudations, surface staining, expansion causing structural deformation, relative movement or displacement, misalignment or distortion of attached components for detection of expansion due to alkali-aggregate reactivity in concrete. 13. Quantitative baseline inspection data will be established against acceptance criteria provided in the enhanced Structures Monitoring program prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria are acceptable in lieu of performing a new baseline inspection. 14. Provide evaluation criteria for structural concrete by using quantitative second tier criteria in Chapter 5 of ACI 349.3R-02. 15. Clarify that loose bolts and nuts are not acceptable unless accepted by engineering evaluations.		

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
34	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants is an existing program that will be enhanced to: 1. Add the following structures to the scope of the program: a. Unit 1 Rock Dike b. Unit 2 Revetment-Ditch System (260 ft which replaced Unit 1 Rock Dike) 2. Explicitly include the following components within the scope of the program: a. Trash racks b. Sluice gates 3. Implement preventive actions to emphasize proper selection of bolting materials and lubricants and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For ASTM A325 and ASTM A490 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection will be in accordance with Section 2 of Research Council for Structural Connection publication "Specification for Structural Joints Using High-Strength Bolts." 4. Perform periodic inspections of water-control structures on an interval not to exceed five years except for the intake tunnel and discharge tunnel. 5. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R-02 with respect to knowledge of inservice inspection of concrete and visual acuity requirements. 6. Develop a new implementing procedure or revise an existing implementing procedure to address aging management of inaccessible areas exposed to potentially aggressive groundwater/soil environment that will include the following: a. Monitor raw water and ground water chemistry for pH, chlorides, and sulfates on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year) from locations that are representative of the groundwater in contact with structures within the scope of subsequent license renewal. b. Develop engineering evaluations to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering	Program will be enhanced and initial engineering evaluation completed no later than six months prior to the subsequent period of extended operation. Baseline inspections will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.34

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Inspection of Water-Control Structures Associated with Nuclear Power Plants (continued)	evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or increased frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil. c. Develop the initial engineering evaluations prior to the subsequent period of extended operation. Develop follow-up engineering evaluations on an interval not to exceed five years. d. If warranted based on the engineering evaluations, perform focused inspections of representative, accessible (leading indicator) structural elements, or if accessible areas will not be leading indicators for the potential aging mechanisms, excavate and inspect buried concrete elements exposed to potentially aggressive groundwater/soil. e. If degraded concrete is identified, as part of the focused inspections of leading indicators (representative, accessible or exposed inaccessible concrete), enter adverse results that exceed ACI 349.3R-02 tier 2 criteria into the corrective action program, and expose inaccessible concrete so that the extent of the condition can be determined, baseline conditions documented, and additional actions identified such as repairs, new preventive actions, additional evaluations, and future inspections. 7. Quantitative baseline inspection data will be established against acceptance criteria provided in the enhanced Inspection of Water-Control Structures Associated with Nuclear Power Plants program prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria are acceptable in lieu of performing a new baseline inspection. 8. Monitor and trend indications of groundwater infiltration or through-concrete leakage. If leakage volumes allow, procedures will be revised to clarify that water chemistry analysis should be considered for parameters including pH, as well as mineral, chloride, sulfate and iron content in the water to assess for potential impact on age-related degradation of concrete or steel reinforcement. This assessment may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels.		

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
	Inspection of Water-Control Structures Associated with Nuclear Power Plants (continued)	9. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 10. Provide evaluation criteria for structural concrete using quantitative second tier criteria in Chapter 5 of ACI 349.3R-02. 11. Clarify that loose bolts and nuts are not acceptable unless accepted by engineering evaluations.		
35	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance is an existing program that will be enhanced to: 1. Require personnel qualifications meet the requirements discussed in ASTM D 5163-08, paragraph 9.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.35
36	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 is an existing program that will be enhanced to: 1. Evaluate plant specific operating experience for previously identified and mitigated adverse localized environments' cumulative aging effects applicable to in-scope cable and connection insulation to confirm that the insulation's intended functions continue to be supported during the subsequent period of extended operation. 2. Perform testing of a sample population when a large number of cables are identified as degraded. The sample size will be 20 percent of each affected cable and connection type with a maximum sample size of 25.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.36

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
37	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 is an existing program that will be enhanced to: 1. Add the electrical cables and connections for the following neutron monitors to the scope of the program: a. Source range monitors 2. Add the electrical cables and connections for the following radiation monitors to the scope of the program: a. Reactor building ventilation radiation monitors 3. Review calibration or surveillance results of circuits in the scope of this program at least once every 10 years. The first periodic review will be performed prior to the subsequent period of extended operation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Reviews and test required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.37
38	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 is an existing program that will be enhanced to: 1. Perform cable testing of the circuits in the scope of this program at a frequency of at least once every six years. The first periodic test will be performed prior to the subsequent period of extended operation. 2. Perform inspections for water accumulation in handholes in the scope of this program after event driven occurrences that could result in water accumulation and cable submergence. 3. Perform annual inspections for water accumulation in handholes in the scope of this program. The first periodic inspection will be performed prior to the subsequent period of extended operation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Tests and inspections required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.38

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
39	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 aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables that are within the scope of license renewal and potentially exposed to significant moisture.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.39
40	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 aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, inaccessible or underground (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) that are within the scope of license renewal and potentially exposed to significant moisture.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.40

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
41	Metal Enclosed Bus	The Metal Enclosed Bus aging management program is an existing program that will be enhanced to: 1. Perform periodic inspections of the isophase bus from the main generator to the main step-up transformers to the station service transformer and a sample of metal enclosed bus bolted connections. The first periodic inspection will be performed prior to the subsequent period of extended operation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.41
42	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 aging management program is a new condition monitoring program that will require testing of a representative sample of electrical connections 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.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Tests and evaluations required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.2.1.42
43	Fatigue Monitoring	Existing program is credited.	Ongoing	Section A.3.1.1
44	Neutron Fluence Monitoring	Existing program is credited.	Ongoing	Section A.3.1.2

TABLE A.5 – SUBSEQUENT LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
45	Environmental Qualification of Electric Equipment	Environmental Qualification of Electrical Equipment is an existing program that will be enhanced to: 1. Visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic inspection will be performed prior to the subsequent period of extended operation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.	Section A.3.1.3
46	Operating Experience	Existing program is credited.	Ongoing	Section A.1.6

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B.1 Introduction

B.1.1 Overview

Subsequent License renewal Aging Management Program (AMP) descriptions are provided in this appendix for each program credited for managing aging effects based upon the Aging Management Review (AMR) results provided in Sections 3.1 through 3.6 of this application.

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 ten 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 “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.

Credit has been taken for existing plant programs whenever possible. As such, all programs and activities associated with a system, structure, component, or commodity grouping were considered. Existing programs and activities that apply to systems, structures, components, or commodity groupings were reviewed to determine whether they include the necessary actions to manage the effects of aging.

Existing plant programs may have been based on a regulatory commitment or requirement, or aging management activities credited for the first license renewal, or a combination of both. Many of these existing programs include the required license renewal 10-element attributes and have been demonstrated to adequately manage the identified aging effects. If an existing program did not adequately manage an identified aging effect, the program was enhanced as necessary. Occasionally, the creation of a new program was necessary.

B.1.2 Method of Discussion

For those AMPs that are consistent with the assumptions made in Sections X and XI of NUREG-2191, or are consistent with exceptions or enhancements, each program discussion is presented in the following format:

- A Program Description abstract of the overall program form and function is provided.
- A NUREG-2191 consistency statement is made about the program.
- Exceptions to the NUREG-2191 program are outlined and a justification for the exceptions is provided.
- Enhancements or additions to the Nine Mile Point Nuclear Station, Unit 1 program are provided. Refer to Appendix A for a discussion of the implementation schedule.
- Operating Experience (OE) information specific to the program is provided.
- A Conclusion section provides a statement of reasonable assurance that the program is effective, or will be effective when implemented, if new or enhanced.

The plant specific AMPs are described in terms of the 10 program elements in NUREG-2192, Section A.1.2.3 “Aging Management Program Elements.”

B.1.3 Quality Assurance Program and Administrative Controls

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, components (SSCs), and commodity groups that are subject to AMR. Generically, the three elements are applicable as follows:

Corrective Actions:

A single corrective action program is applied regardless of the safety classification of the system, structure, component, or commodity group. Corrective actions are implemented through the initiation of an issue report (IR) in accordance with the corrective action program in place to meet the requirements of 10 CFR 50, Appendix B. The corrective action program requires the initiation of an IR for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction, or loss of function. Site documents that implement aging management programs for license renewal direct that an IR be prepared in accordance with those procedures whenever non-conforming conditions are found (i.e., the acceptance criteria are not met).

Equipment deficiencies are corrected through the work control process in accordance with plant procedures. The corrective action program specifies that for equipment deficiencies an IR be initiated for condition identification, assignment of significance level and investigation class, investigation, corrective action determination, investigation report review and approval, action tracking, and trend analysis.

The corrective action program implements the requirements of NO-AA-10, the Constellation Energy Generation Company Quality Assurance Topical Report (QATR), Chapter 16, “Corrective Action.” Specifically, measures are established to assure that conditions adverse to quality, such as failures, malfunctions, adverse trends, deficiencies, deviations, defective material, design errors, equipment, and

nonconformances, are identified and corrected. In cases of significant conditions adverse to quality, the cause of the condition is determined and documented, resolution determined and documented, and corrective action taken and documented to preclude recurrence. In addition, the cause of the significant condition adverse to quality and the corrective action taken are reported to appropriate levels of management.

Confirmation Process:

The focus of the confirmation process is on the follow-up actions that must be taken to verify effective implementation of corrective actions. The measure of effectiveness is in terms of correcting and precluding repetition of adverse conditions. The corrective action program includes provisions for timely evaluation of adverse conditions and implementation of corrective actions required, including root cause determinations and prevention of recurrence where appropriate (e.g., significant conditions adverse to quality). The corrective action program provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The corrective action program also includes monitoring for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions results in the initiation of an IR. The aging management programs required for subsequent license renewal would also result in identification of related unsatisfactory conditions due to ineffective corrective action.

Since the same 10 CFR 50, Appendix B corrective actions and confirmation process is applied for nonconforming safety-related and nonsafety-related systems, structures, and components subject to AMR for subsequent license renewal, the corrective action program is consistent with the NUREG-2191 elements.

Administrative Controls:

The document control process applies to all generated 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, "Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants." Implementation is further defined in NO-AA-10, the Constellation Energy Generation Company QATR, Chapter 6, "Document Control."

Administrative controls procedures provide information on procedures, instructions and other forms of administrative control documents, as well as guidance on classifying these documents into the proper document type and as-building frequency. Revisions will be made to procedures and instructions that implement or administer aging management program requirements for the purposes of managing the associated aging effects for the subsequent period of extended operation.

B.1.4 Operating Experience

Operating experience from internal (also referred to as in-house operating experience) and external (also referred to as industry) sources is captured and systematically reviewed on an ongoing basis in accordance with the Quality Assurance program, which meets the requirements of 10 CFR Appendix B, and the Operating Experience (OE) program, which meets the requirements of NUREG- 0737, "Clarification of TMI

Action Plan Requirements,” Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff.” The OE program interfaces with and relies on active participation in the Institute of Nuclear Power Operations (INPO) Operating Experience program, as endorsed by the NRC.

Operating experience is used at NMP1 to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants. As part of the Constellation fleet, NMP1 personnel receive operating experience (internal and external to Constellation) daily. The OE process includes screening, evaluation, and acting on operating experience documents and information to prevent or mitigate the consequences of similar events. The OE process includes review of operating experience from external and internal sources. External operating experience may include such things as INPO documents (e.g., Significant Operating Experience Reports, INPO Event Reports, etc.), NRC documents (e.g., NUREG-2191 Revisions, Information Notices, Interim Staff Guidance, Regulatory Issue Summaries, etc.), and other documents (e.g., EPRI Category 1 and 2 Technical Reports, 10 CFR Part 21 Notifications, etc.), as well as relevant research and development information. Internal operating experience may include event investigations, trending reports, and lessons learned from Nine Mile Point Nuclear Station (NMPNS) and Constellation fleet events as captured in program health reports, program assessments, and in the 10 CFR Part 50, Appendix B corrective action program.

The Constellation fleet OE program that is implemented at NMP1 is an ongoing program that is consistent with the expectations outlined in NUREG-2192 (SRP-SLR), Appendix A.4, “Operating Experience for Aging Management Programs.” The systematic review of plant-specific and industry operating experience concerning aging management and age-related degradation ensures that the license renewal aging management programs (AMPs) are, and will continue to be, effective in managing the aging effects for which they are credited. Operating experience 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) aging management programs, to determine if changes to AMPs or new AMPs are needed. The AMPs are either enhanced or new AMPs developed, as appropriate, when it is determined through the evaluation of operating experience that the effects of aging may not be adequately managed. AMPs are informed by the review of operating experience on an ongoing basis, regardless of the AMP’s implementation schedule. The Constellation process directs the reporting of plant-specific operating experience on age-related degradation and aging management to the industry through the INPO OE program consistent with the guidance in NEI 14-13, “Use of Industry Operating Experience for Age-Related Degradation and Aging Management Programs.” In addition, the Constellation process requires that periodic AMP effectiveness reviews are conducted at least once within every five-year period. The Constellation process refers to and is consistent with the guidance of NEI 14-12, “Aging Management Program Effectiveness.”

Each AMP summary in this appendix contains a discussion of operating experience relevant to the program. This information was obtained through the review of internal operating experience captured by the corrective action program, program assessments, program health reports, and through the review of external operating

experience. Additionally, operating experience was obtained through interviews with strategic engineers, program engineers, and other plant personnel. New programs utilized internal and external operating experience, as applicable, and the AMP summaries in this appendix discuss the operating experience and associated corrective actions as they relate to implementation of the new program. The operating experience in each AMP summary identifies past corrective actions that 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 maintained during the subsequent period of extended operation.

Consistent with the guidance in Section 6 of Appendix B of NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,” effectiveness reviews of first license renewal aging management programs/activities (i.e., FLR AMPs) were performed, and are presented within the SLRA Appendix B AMP sub-sections that are most related to those FLR AMPs. For example, there were several FLR AMPs related to water chemistry control. An assessment of the effectiveness of these is presented within Section B.2.1.2, which describes the SLR AMP for the Water Chemistry aging management program. These effectiveness reviews are presented as the first operating experience example in the related SLRA AMP operating experience section (i.e., as OE #1). As applicable, these effectiveness review summaries may reveal such things as: 1) whether significant plant OE was identified due to AMP implementation, 2) whether significant relevant plant OE occurred that was not identified through AMP implementation, 3) how internal or external OE was used to inform or enhance the AMP, and 4) how the effectiveness of the AMP is being monitored.

NUREG 2192 Section 1.2.2 “Applications with Approved Extended Power Upgrades” requires all license renewal applications with an approved extended power upgrade (EPU) to perform an OE review and its impacts on AMPs for SCs before entering the subsequent period of extended operation. NMP1 has not submitted a request for an extended power upgrade.

B.1.5 NUREG-2191 Chapter XI Aging Management Programs

Table B-1 provides a list of the NMP1 NUREG-2191 Chapter XI AMPs and indicates whether the AMP is considered new or an existing program. Existing AMPs are based on either an existing LR AMP or existing plant program. The programs are based on NUREG-2191 Chapter XI AMPs as identified in Table B-1 and as described in Section B.2.1. There are no NMP1 plant-specific programs as identified in Section B.2.2.

Table B-1
NMP1 NUREG-2191 Chapter XI Aging Management Programs

SLRA Section	NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
B.2.1.1	XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing
B.2.1.2	XI.M2	Water Chemistry	Existing
B.2.1.3	XI.M3	Reactor Head Closure Stud Bolting	Existing
B.2.1.4	XI.M4	BWR Vessel ID Attachment Welds	Existing
B.2.1.5	XI.M7	BWR Stress Corrosion Cracking	Existing
B.2.1.6	XI.M8	BWR Penetrations	Existing
B.2.1.7	XI.M9	BWR Vessel Internals	Existing
B.2.1.8	XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	New
B.2.1.9	XI.M17	Flow-Accelerated Corrosion	Existing
B.2.1.10	XI.M18	Bolting Integrity	Existing
B.2.1.11	XI.M20	Open-Cycle Cooling Water System	Existing
B.2.1.12	XI.M21A	Closed Treated Water Systems	Existing
B.2.1.13	XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Existing
B.2.1.14	XI.M24	Compressed Air Monitoring	Existing
B.2.1.15	XI.M26	Fire Protection	Existing
B.2.1.16	XI.M27	Fire Water System	Existing
B.2.1.17	N/A	Not Used	N/A
B.2.1.18	XI.M30	Fuel Oil Chemistry	Existing
B.2.1.19	XI.M31	Reactor Vessel Material Surveillance	Existing
B.2.1.20	XI.M32	One-Time Inspection	New
B.2.1.21	XI.M33	Selective Leaching	New
B.2.1.22	XI.M35	ASME Code Class 1 Small-Bore Piping	New
B.2.1.23	XI.M36	External Surfaces Monitoring of Mechanical Components	New
B.2.1.24	XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	New
B.2.1.25	XI.M39	Lubricating Oil Analysis	Existing

SLRA Section	NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
B.2.1.26	XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Existing
B.2.1.27	XI.M41	Buried and Underground Piping and Tanks	Existing
B.2.1.28	XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	New
B.2.1.29	XI.S1	ASME Section XI, Subsection IWE	Existing
B.2.1.30	XI.S3	ASME Section XI, Subsection IWF	Existing
B.2.1.31	XI.S4	10 CFR Part 50, Appendix J	Existing
B.2.1.32	XI.S5	Masonry Walls	Existing
B.2.1.33	XI.S6	Structures Monitoring	Existing
B.2.1.34	XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing
B.2.1.35	XI.S8	Protective Coating Monitoring and Maintenance	Existing
B.2.1.36	XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Existing
B.2.1.37	XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Existing
B.2.1.38	XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Existing
B.2.1.39	XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New
B.2.1.40	XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New
B.2.1.41	XI.E4	Metal Enclosed Bus	Existing
B.2.1.42	XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New

B.1.6 Plant-Specific Aging Management Programs

None. The Nine Mile Point Nuclear Station, Unit 1 Subsequent License Renewal Application does not include plant-specific aging management programs.

B.1.7 NUREG-2191 Chapter X Aging Management Programs

Table B-2 provides a list of the NMP1 NUREG-2191 Chapter X AMPs and indicates whether the AMP is considered new or an existing program. Existing AMPs are based on either an existing LR AMP or existing plant program. The NUREG-2191 Chapter X AMPs are described in Section B.3 of this appendix as indicated.

Table B-2
NMP1 NUREG-2191 Chapter X Aging Management Programs

SLRA Section	NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
B.3.1.1	X.M1	Fatigue Monitoring	Existing
B.3.1.2	X.M2	Neutron Fluence Monitoring	Existing
B.3.1.3	X.E1	Environmental Qualification of Electric Components	Existing

B.2 Aging Management Programs

B.2.0 NUREG-2191 Aging Management Program Correlation

The correlation between the NUREG-2191 (Generic Aging Lessons Learned (GALL-SLR)) programs and the NMP1 Aging Management Programs (AMPs) is shown in Table B-3 below. Table B-4 provides a summary of the AMP consistency with NUREG-2191 by identifying whether or not the AMP has any enhancements to align with NUREG-2191 or takes exception to NUREG-2191 recommendations.

Table B-3
NUREG-2191 Aging Management Program Correlation

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	NMP1 PROGRAM
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.1.1)
XI.M2	Water Chemistry	Water Chemistry (Section B.2.1.2)
XI.M3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting (Section B.2.1.3)
XI.M4	BWR Vessel ID Attachment Welds	BWR Vessel ID Attachment Welds (Section B.2.1.4)
XI.M5	Deleted	Not Applicable
XI.M6	Deleted	Not Applicable
XI.M7	BWR Stress Corrosion Cracking	BWR Stress Corrosion Cracking (Section B.2.1.5)
XI.M8	BWR Penetrations	BWR Penetrations (Section B.2.1.6)
XI.M9	BWR Vessel Internals	BWR Vessel Internals (Section B.2.1.7)
XI.M10	Boric Acid Corrosion	Not Applicable (NMP1 is a BWR)
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs only)	Not Applicable (NMP1 is a BWR)

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	NMP1 PROGRAM
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section B.2.1.8)
XI.M16A	PWR Vessel Internals	Not Applicable (NMP1 is a BWR)
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (Section B.2.1.9)
XI.M18	Bolting Integrity	Bolting Integrity (Section B.2.1.10)
XI.M19	Steam Generators	Not Applicable (NMP1 is a BWR)
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (Section B.2.1.11)
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems (Section B.2.1.12)
XI.M22	Boraflex Monitoring	Not Applicable (This program is not credited for aging management. Boraflex is not a credited neutron-absorbing material in the NMP1 spent fuel pool racks).
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 (Section B.2.1.13)
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring (Section B.2.1.14)
XI.M25	BWR Reactor Water Cleanup System	Not Applicable. (NMP1 does not have any components within the scope of the XI.M25 AMP)
XI.M26	Fire Protection	Fire Protection (Section B.2.1.15)
XI.M27	Fire Water System	Fire Water System (Section B.2.1.16)
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Not Applicable (NMP1 does not have any components within the scope of the XI.M29 AMP)

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	NMP1 PROGRAM
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry (Section B.2.1.18)
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance (Section B.2.1.19)
XI.M32	One-Time Inspection	One-Time Inspection (Section B.2.1.20)
XI.M33	Selective Leaching	Selective Leaching (Section B.2.1.21)
XI.M35	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping (Section B.2.1.22)
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components (Section B.2.1.23)
XI.M37	Flux Thimble Tube Inspection	Not Applicable (NMP1 is a BWR)
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.1.24)
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (Section B.2.1.25)
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section B.2.1.26)
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks (Section B.2.1.27)
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 (Section B.2.1.28)
XI.M43	High-Density Polyethylene (HDPE) Piping and Carbon Fiber-Reinforced Polymer (CFRP) Repaired Piping	Not applicable. (NMP1 does not have HDPE piping or CFRP repaired piping.
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE (Section B.2.1.29)

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	NMP1 PROGRAM
XI.S2	ASME Section XI, Subsection IWL	Not Applicable (NMP1 does not have a reinforced prestressed concrete containment)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (Section B.2.1.30)
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J (Section B.2.1.31)
XI.S5	Masonry Walls	Masonry Walls (Section B.2.1.32)
XI.S6	Structures Monitoring	Structures Monitoring (Section B.2.1.33)
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B.2.1.34)
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance (Section B.2.1.35)
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 (Section B.2.1.36)
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 (Section B.2.1.37)
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 (Section B.2.1.38)

NUREG-2191 NUMBER	NUREG-2191 PROGRAM	NMP1 PROGRAM
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 (Section B.2.1.39)
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 (Section B.2.1.40)
XI.E4	Metal Enclosed Bus	Metal Enclosed Bus (Section B.2.1.41)
XI.E5	Fuse Holders	Not Applicable (NMP1 Fuse Holders (not part of active equipment) have no aging effects requiring management).
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 (Section B.2.1.42)
XI.E7	High-Voltage Insulators	Not applicable (The High-Voltage Insulators have no aging effects requiring management).
X.M1	Fatigue Monitoring	Fatigue Monitoring (Section B.3.1.1)
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring (Section B.3.1.2)
X.S1	Concrete Containment Unbonded Tendon Prestress	Not applicable (NMP1 does not have a containment with prestressed tendons)
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (Section B.3.1.3)

Table B-4
NMP1 Aging Management Program Consistency with NUREG-2191

NMP1 AMP	SLRA Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements Yes/No	Exceptions Yes/No
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B.2.1.1	XI.M1	No	No
Water Chemistry	B.2.1.2	XI.M2	No	Yes
Reactor Head Closure Stud Bolting	B.2.1.3	XI.M3	No	No
BWR Vessel ID Attachment Welds	B.2.1.4	XI.M4	No	No
BWR Stress Corrosion Cracking	B.2.1.5	XI.M7	No	No
BWR Penetrations	B.2.1.6	XI.M8	No	No
BWR Vessel Internals	B.2.1.7	XI.M9	Yes	No
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B.2.1.8	XI.M12	No (New)	No
Flow-Accelerated Corrosion	B.2.1.9	XI.M17	Yes	Yes
Bolting Integrity	B.2.1.10	XI.M18	Yes	Yes
Open-Cycle Cooling Water System	B.2.1.11	XI.M20	Yes	No
Closed Treated Water Systems	B.2.1.12	XI.M21A	Yes	No
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.1.13	XI.M23	Yes	No
Compressed Air Monitoring	B.2.1.14	XI.M24	Yes	No
Fire Protection	B.2.1.15	XI.M26	Yes	No
Fire Water System	B.2.1.16	XI.M27	Yes	Yes
Not Used	B.2.1.17	N/A	N/A	N/A
Fuel Oil Chemistry	B.2.1.18	XI.M30	Yes	Yes
Reactor Vessel Material Surveillance	B.2.1.19	XI.M31	Yes	No
One-Time Inspection	B.2.1.20	XI.M32	No (New)	Yes
Selective Leaching	B.2.1.21	XI.M33	No (New)	Yes
ASME Code Class 1 Small-Bore Piping	B.2.1.22	XI.M35	No (New)	No
External Surfaces Monitoring of Mechanical Components	B.2.1.23	XI.M36	No (New)	No

NMP1 AMP	SLRA Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements Yes/No	Exceptions Yes/No
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.1.24	XI.M38	No (New)	No
Lubricating Oil Analysis	B.2.1.25	XI.M39	Yes	No
Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B.2.1.26	XI.M40	No	No
Buried and Underground Piping and Tanks	B.2.1.27	XI.M41	Yes	Yes
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.1.28	XI.M42	No (New)	Yes
ASME Section XI, Subsection IWE	B.2.1.29	XI.S1	Yes	Yes
ASME Section XI, Subsection IWF	B.2.1.30	XI.S3	Yes	No
10 CFR Part 50, Appendix J	B.2.1.31	XI.S4	No	No
Masonry Walls	B.2.1.32	XI.S5	Yes	Yes
Structures Monitoring	B.2.1.33	XI.S6	Yes	Yes
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.1.34	XI.S7	Yes	Yes
Protective Coating Monitoring and Maintenance	B.2.1.35	XI.S8	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.1.36	XI.E1	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	B.2.1.37	XI.E2	Yes	No
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.1.38	XI.E3A	Yes	No
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.1.39	XI.E3B	No (New)	No

NMP1 AMP	SLRA Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements Yes/No	Exceptions Yes/No
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.1.40	XI.E3C	No (New)	No
Metal Enclosed Bus	B.2.1.41	XI.E4	Yes	No
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.1.42	XI.E6	No (New)	No
Fatigue Monitoring	B.3.1.1	X.M1	No	No
Neutron Fluence Monitoring	B.3.1.2	X.M2	No	No
Environmental Qualification of Electric Equipment	B.3.1.3	X.E1	Yes	No

B.2.1 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter XI programs credited for managing the effects of aging.

B.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing condition monitoring program which manages the aging effects of cracking, loss of fracture toughness, and loss of material for Class 1, 2, and 3 pressure-retaining components piping and components exposed to a reactor coolant, treated water, steam, and air-indoor uncontrolled environments. This program includes periodic visual, surface, and volumetric examination of Class 1, 2, and 3 pressure-retaining components. The program implements the Inservice Inspection (ISI) requirements of ASME Code, Section XI, for Class 1, 2, and 3 pressure-retaining components, their integral attachments, and pressure-retaining bolting. Examination of these components is in accordance with Subsections IWB, IWC, and IWD, respectively.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program includes augmented inservice inspection requirements for periodic examination of the reactor vessel feedwater and control rod drive return line (CRDRL) nozzles in accordance with the NRC-approved recommendations provided within BWR Owners Group (BWROG) Licensing Topical Report, "Alternate BWR Feedwater Nozzle Inspection Requirements," GE-NE-523-A71-0594-A, Revision 1, May 2000.

In addition, although not required by ASME Section XI, visual inspection and leakage testing of the emergency condenser tubes and tube sheets will be implemented through this program for subsequent license renewal.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program implements the required component examination schedule per ASME 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 Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. The examination methods specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are based on approved industry standards for detecting degradation of components. Indications and relevant conditions detected during examinations are entered into the corrective action program and evaluated in accordance with ASME 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 conformance with IWA-4000.

For the fifth ISI Interval, NMP1's inspection program for ASME Section XI Examination Categories B-F, B-J, C-F-1, C-F-2, C-A, and C-B will be governed by risk-informed requirements. The RI-ISI Program methodology is defined in ASME code case N-716-1.

In accordance with 10 CFR 50.55a(g)(4), the ASME Code, Section XI program code of record interval is updated each successive inspection interval (or two consecutive inspection intervals per 10 CFR 50.55a(y), as applicable) to comply with the requirements of the latest edition of the ASME Code specified eighteen months before the start of the inspection interval. Any deviation from ASME Code, Section XI requirements must be approved by the NRC through a relief request.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are applicable to all Constellation plants. The equivalent ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program for Peach Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is consistent with the ten elements of aging management program XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an AMP effectiveness review was performed using Constellation procedural guidance and industry standards. The AMP effectiveness review assessed the key attributes of the existing ASME Section XI, Subsections IWB, IWC and IWD AMP effectiveness, including but not limited to detection of aging effects, corrective actions, evaluation of industry and plant-specific operating experience informing the AMP, and verifying license renewal commitments are properly maintained. The review concluded that inspections have been performed in accordance with specified commitment implementation activities (e.g., PM tasks, walkdowns, inspections). No adverse trends or deficiencies

were identified during the inspections or any previous corrective actions. The program was determined to be effectively managing aging in accordance with the existing 10 elements of the AMP.

This operating experience example provides objective evidence of aging management program effectiveness during the first period of extended operation. This example also demonstrates that periodic program effectiveness reviews are performed to ensure that program effectiveness is maintained and to drive continuous improvement.

2. During the Spring 2023 refueling outage, ultrasonic examinations (UT) were performed on the recirculation inlet nozzle safe end-to-nozzle dissimilar metal weld. One relevant indication was recorded which was not acceptable for continued service in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, IWB-3600. This condition was entered into the corrective action program (CAP).

The defect was characterized by phased array ultrasonic examination and found to be an axially oriented flaw and approximately 83 percent through-wall. The indication was inside diameter (ID) connected with attributes that were indicative of intergranular stress corrosion cracking (IGSCC). The immediate consequence of this inspection result was that the reactor vessel nozzle (penetration) was declared inoperable.

The flaw was repaired with a leakage barrier in 2023 and a full structural weld overlay during the 2025 refueling outage. The repair was performed in accordance with NRC-approved relief request I5R-11 (ADAMS Accession No. ML23156A682). In addition to the repair, NMP1 performed an extent of condition assessment which resulted in all 10 reactor recirculation dissimilar metal welds being inspected in 2023. Dissimilar metal welds for the core spray nozzle-to-safe end and emergency condenser nozzle-to-safe ends were also inspected.

A system leakage test and VT-2 visual examination were performed on the weld overlay in accordance with IWA-5000 following the completion of the weld overlay and acceptance examinations.

This operating experience example provides objective evidence that the current ISI program is effective in managing and evaluating aging effects of Class 1, 2, and 3 ASME components and welds. Continued implementation of the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD aging management program will ensure that the piping welds within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

3. In 2021, encoded automated phased array examinations were performed on the 'C' reactor recirculation nozzle-to-safe end weld, two axial indications were recorded with measurable through-wall dimensions. This condition was entered into the corrective action program (CAP). The first indication was deemed acceptable, however, the second was unacceptable per Table 3514-1 in ASME Section XI, 2013 Edition. In addition, the 'D' reactor recirculation nozzle-to-safe end weld was also examined, there were multiple indications with measurable through-wall dimensions. There were four acceptable indications and nine

unacceptable indications per Table-3514-1 in ASME Section XI, 2013 Edition. All flaws were connected to the ID.

These indications were visible in previously encoded data and were characterized as geometry responses. Due to the current technique providing more data, NMP1 was able to ascertain a through-wall dimension to generate an aspect ratio and therefore recorded these flaws, even though they were not service induced flaws. The flaws were constrained to the 316NG (nuclear grade-low carbon) material which is considered stress corrosion crack (SCC) resistant material. It was determined that the indications initiated at the inside surface near the weld root area of the austenitic weld, and extended axially into the safe-end material.

The NDE reports have concluded that the indications were not service-induced, and not suspected to be intragranular stress corrosion cracking (IGSCC). They were treated as original construction planar flaws. Since several indications exceeded the acceptance criteria, an ASME Code, Section XI, IWB-3600 evaluation was required for these indications.

The flaw evaluation was performed per ASME Code, Section XI, 2013 Edition, IWB-3600 and Nonmandatory Appendix C. Stress corrosion cracking (SCC) and fatigue crack growth analysis (for an operating period of two years) was performed using the bounding initial flaw size. Fatigue crack growth was evaluated to be negligible. The results show that after an operating cycle of two years with SCC growth, the final flaw length and final aspect ratio are below the allowable flaw length and allowable aspect ratio.

These welds have been successively inspected in 2023 and 2025, and results show relatively no change.

This operating experience example provides objective evidence that ASME Section XI examinations are effective at identifying degraded conditions. When degraded conditions are identified, the conditions are evaluated, corrective actions are taken and the extent of identified degraded conditions are addressed prior to a loss of intended function.

The operating experience relative to the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of fracture toughness, and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.2 Water Chemistry

Program Description

The Water Chemistry aging management program is an existing program whose activities mitigate the loss of material due to corrosion; cracking due to stress corrosion cracking (SCC) and related mechanisms; and reduction of heat transfer due to fouling in components exposed to a reactor coolant, steam, or treated water environment. The program includes periodic monitoring of the reactor coolant, steam, and treated water and control of parameters such as conductivity, chloride, and sulfate concentrations within the guidelines of BWRVIP-190, Revision 2 (EPRI TR-3002025550), “BWR Vessel and Internal Project, BWR Water Chemistry Guideline,” in order to minimize aging effects.

The NMP1 Water Chemistry aging management program consists of monitoring and controlling the chemical environments of those systems that are exposed to reactor water, steam, condensate, feedwater, control rod drive water, demineralized water, torus water, and spent fuel pool water, such that aging effects of system components are minimized in accordance with BWRVIP-190, Revision 2.

Major component types managed by this program include the reactor vessel, reactor internals, piping, piping elements, heat exchangers, and tanks. Reactor water, condensate, control rod drive water, feedwater, demineralized water storage tank water, torus water, spent fuel pool water, condensate storage tank water, and stator cooling water are classified as treated water for aging management.

The water chemistry program is credited for mitigating loss of material and cracking for components exposed to sodium pentaborate. The Liquid Poison System contains a demineralized water and sodium pentaborate solution controlled in accordance with plant procedures and Technical Specifications. The managing of aging effects on Liquid Poison System components subject to the sodium pentaborate environment relies on monitoring and control of Liquid Poison System storage tank makeup water chemistry. The makeup water, from the demineralized water storage tank, is monitored in lieu of the sodium pentaborate solution in the storage tank, because the sodium pentaborate would mask the chemistry parameters monitored. The chloride content of the sodium pentaborate powder is certified by the manufacturer to have low levels of chloride contamination.

The NMP1 Water Chemistry manages the treated water contained within the emergency condensers with additional monitoring for conductivity and radioactivity of emergency condenser shell side water.

The NMP1 Water Chemistry aging management program also monitors and controls the chemical environment of the stator cooling water system such that aging effects of system components are minimized in accordance with EPRI TR-3002000420, “Turbine Generator Auxiliary System Maintenance Guide Volume 4: Generator Stator Cooling Water System,” and GEK 45942, “Stator Winding Cooling Water System Operation and Flushing (Constant Flow),” guidelines.

The Water Chemistry program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are applicable to all Constellation BWR plants. The equivalent Water

Chemistry program for Peach Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Water Chemistry program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Water Chemistry aging management program is consistent with the ten elements of aging management program XI.M2, “Water Chemistry,” specified in NUREG-2191, with the following exceptions:

Exceptions to NUREG-2191

1. The NUREG-2191 Revision 1 Chapter XI.M2, “Water Chemistry,” aging management program monitors parameters of various plant water systems in accordance with the guidelines contained in BWRVIP-190, Revision 1. Nine Mile Point Nuclear Station, Unit 1 Water Chemistry aging management program is based on BWRVIP-190, Revision 2. **Program Element Affected: Scope of Program (Element 1), Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), Corrective Actions (Element 7).**

Justification for Exception

EPRI periodically revises the water chemistry guidelines as new information becomes available based on industry operating experience, best practices, and research. In all instances, the chemistry parameter guidelines for Action Levels in BWRVIP-190, Revision 2 are the same or more restrictive than in BWRVIP 190, Revision 1. In no instances are the chemistry parameter guidelines relaxed. Therefore, the NMP1 Water Chemistry aging management program, as defined by BWRVIP-190, Revision 2, will continue to be effective in mitigating the loss of material due to corrosion, cracking due to stress corrosion cracking and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a treated water environment.

2. The NUREG-2191 Chapter XI.M2, “Water Chemistry,” aging management program monitors parameters of various plant water systems in accordance with the guidelines contained in the BWRVIP-190. The scope of the NMP1 Water Chemistry aging management program is expanded to include the Main Generator and Auxiliaries System which does not fall under the scope of BWRVIP-190. **Program Element Affected: Scope of Program (Element 1), Preventive Actions (Element 2), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), Corrective Actions (Element 7)**

Justification for Exception

There is currently no NUREG-2191 program that addresses water chemistry for stator cooling water. The Water Chemistry program is being expanded to include chemistry controls for this water. The critical chemistry parameters for stator cooling water are monitored in accordance with EPRI TR-3002000420, "Turbine Generator Auxiliary System Maintenance Guide Volume 4: Generator Stator Cooling Water System" and equipment manufacturer guidelines. A review of plant operating experience indicates that the chemistry controls for this environment are adequate to mitigate aging. A similar exception was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Dresden Nuclear Station, Units 2 and 3 (ADAMS Accession No. ML25251A150).

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Water Chemistry program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program (AMP) effectiveness review of NMP1 Water Chemistry Control Program was performed. The AMP was evaluated, to ensure it meets regulatory requirements and effectively mitigates aging effects of in scope SSCs that ensuring a loss of function does not occur. The following is a summary of the actions taken and results:
 - This AMP was evaluated to fulfill station procedural requirements by periodically assessing the AMP's effectiveness, focusing on preventing material loss and crack initiation through water chemistry control and monitoring to ensure a loss of function does not occur.
 - Monitoring frequencies and parameters follow EPRI BWRVIP-190 guidelines, with data confirming adherence to sampling requirements and prompt identification of deviations without necessitating increased analysis frequency.
 - Issue Reports related to water chemistry deviations were addressed promptly with cause evaluations and procedural revisions, with no new degradation mechanisms identified or changes needed in degradation rate expectations.

In conclusion, this effectiveness review provides objective evidence that existing aging management program activities are being effectively implemented to mitigate aging effects, and that deficiencies identified during the implementation of the program are entered into the corrective action program for evaluation. Continued implementation of the program will ensure components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

2. In February 2024, during the weekly chemistry sampling the station obtained unexpected results on reactor water samples, on both units, indicating lower than actual soluble zinc. These unexpected results were coincident with the implementation of new sample filters which replaced the existing filters. The existing filters are no longer being manufactured. Recently developed new ion exchange filters were procured and installed.

Following an investigation, the transition from the existing filters to the new filters for x-ray fluorescence (XRF) analysis indicated that only 30 to 40 percent of the expected recovery rate was being seen on the new filters, which had resulted in both reactor water samples indicating lower than expected soluble zinc values. The probable cause was determined to be the XRF has not been calibrated with the new filters installed. The corrective action was to purchase new calibration standards and calibrate the XRF with new filters. Samples were obtained by multiple technicians and run on different instruments. The same results were seen when re-analyzed on different instruments. This ruled out sampling error and instrument failure. The new calibration standards were obtained and XRF was calibrated with the new filters and new calibration standards which resolved the issue.

The above operating experience displays the program's questioning attitude with unexpected results and the corrective action program is entered for evaluation and timely actions to address the identified condition.

3. In April 2019, during reactor water sampling the results identified elevated sulfate levels. Reactor water sulfates are managed by the Water Chemistry aging management program. The sulfate concentrations remained below Technical Specification limits and reactor coolant chemistry remained operable. Investigation revealed the source of the high sulfate concentrations was attributed to hydrogen water chemistry (HWC) hydrogen flow oscillations. No compensatory measures were required by operations or chemistry. The HWC hydrogen flow oscillations issue was entered into the corrective action program for evaluation. A work order was initiated to troubleshoot HWC flow oscillations. The investigation uncovered leakage that resulted in water intrusion into the control system. The leakage issue was repaired which restored stable HWC flow and restored reactor water sulfate to normal levels.

This operating experience example provides objective evidence that the station's monitoring and trending water chemistry processes are effective and entered into the corrective action program to address the issue.

4. In April 2017, during unit start up following a refueling outage, reactor water chloride exceeded the Action Level 1 (AL-1) concentration (greater than 5 ppb). Not maintaining chemistry within specification impacts asset preservation. The source of the elevated chlorides was determined to be from one of six condensate filter demineralizers. Five condensate filter demineralizers are required for power operation. During unit start up one demineralizer is used for short path condensate feedwater flushing. Delays in repairs and procedure deficiencies while returning demineralizers to service contributed to the event. The issue was entered into the corrective action program for evaluation. The evaluation identified several corrective actions, including benchmarking other

stations, revisions to station chemistry procedures, improved chemistry outage preparations, and improved just-in-time outage training focused on demineralizer restoration and startup monitoring which have been effective in managing reactor water chemistry during startup operations.

The above operating experience displays the program's compliance with acceptance criteria. Out of specification readings are entered into the corrective action program for evaluation and timely actions are taken to address the identified condition.

The operating experience relative to the Water Chemistry program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of material, and reduction of heat transfer. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Water Chemistry program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Water Chemistry program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing Water Chemistry program provides reasonable assurance that the cracking, loss of material, and reduction of heat transfer aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.3 Reactor Head Closure Stud Bolting

Program Description

The Reactor Head Closure Stud Bolting aging management program is an existing condition monitoring and preventive program that includes ASME Code, Section XI examinations of reactor head closure studs, flange threads, and associated nuts, washers, and bushings to manage cracking and loss of material. The Reactor Head Closure Stud Bolting aging management program manages these aging effects in an air-indoor uncontrolled environment. The program is based on the examination requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and preventive measures recommended within NRC Regulatory Guide (RG) 1.65, Revision 1, "Materials and Inspections for Reactor Vessel Closure Studs."

The Reactor Head Closure Stud Bolting aging management program implements ASME Code, Section XI inspection requirements through the ISI Program. The ISI program is implemented through procedures, in accordance with the requirements of the ASME Code, Section XI, supplemented with the applicable requirements of 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), the ASME Code, Section XI program code of record interval is updated each successive inspection interval (or two consecutive inspection intervals per 10 CFR 50.55a(y), as applicable) to comply with the requirements of the latest edition of the ASME Code specified eighteen months before the start of the inspection interval.

The program provides for visual and volumetric examinations in accordance with the general requirements of ASME Code, Section XI, Subsection IWA-2000 to monitor for cracking, loss of material, and coolant leakage. The extent and schedule for examining and testing the reactor head closure stud bolting components is as specified in Table IWB-2500-1 for B-G-1 components, "Pressure Retaining Bolting Greater than 2 Inches in Diameter." Each stud receives a volumetric examination, and the surfaces of nuts, washers, and bushings are inspected using VT-1 examination. Volumetric examination of flange threads is not currently required in accordance with approved Relief Request I5R-05. Any future relief request from the requirements of ASME Code, Section XI will be submitted to the NRC for approval in accordance with 10 CFR 50.55a. The reactor vessel flange connection is within the ASME Code Class 1 pressure-retaining boundary that receives a visual VT-2 examination per Exam Category B-P during the system leakage test that is performed during each refueling outage.

Indications and relevant degraded conditions detected during examinations are entered into the corrective action program and evaluated in accordance with ASME Code, Section XI, Subsection IWB-3100 for Class 1 components by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500. Flaw indications or relevant degraded conditions are evaluated in accordance with IWB-3515 or IWB-3517 as indicated in Table IWB-2500-1 and Table 3410-1 of ASME Code, Section XI.

The installed reactor head closure studs and nuts are fabricated from ASME SA-540, Class 3, Grade B-23 or B-24. All installed studs have an actual measured ultimate tensile strength less than 170 ksi. The Reactor Head Closure Stud Bolting aging management program includes all the other preventive measures to mitigate cracking that are described in NRC RG 1.65, Revision 1. No metal plating was

applied to the reactor head closure stud bolting components. A manganese phosphate coating was applied to the reactor head closure studs to improve galling resistance and to improve resistance to corrosion. In addition, a stable lubricant that does not contain molybdenum disulfide is applied to the studs, nuts, and washers each time the reactor vessel head is installed.

NUREG-2191 Consistency

The Reactor Head Closure Stud Bolting aging management program is consistent with the ten elements of aging management program XI.M3, "Reactor Head Closure Stud Bolting," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Reactor Head Closure Stud Bolting aging management program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. Aging management program effectiveness reviews were performed for the Reactor Head Closure Stud Bolting aging management program in 2019 and 2025. The purpose of the aging management program effectiveness reviews was to verify that the intent of the existing aging management program, which is to manage cracking and loss of material of reactor head closure bolting components, is being effectively implemented in the first period of extended operation. The aging management program effectiveness reviews included a review of program implementation activities and relevant issue reports in the corrective action program to verify that potential aging effects are detected prior to loss of intended function.

In addition, the effectiveness reviews included surveys of industry operating experience to determine if any changes or enhancements to the program were warranted.

The reviews confirmed that all required inspections of reactor head closure stud bolting components are being performed in accordance with program requirements. The review of internal and external operating experience did not identify any new or unexpected aging issues. No changes or enhancements to the program were required based on this review.

This operating experience provides objective evidence that the current Reactor Head Closure Stud Bolting aging management program is being effectively implemented to manage aging effects of reactor head closure stud bolting components, and that effectiveness reviews are performed to drive continuous

improvement. Continued implementation of the Reactor Head Closure Stud Bolting aging management program will ensure that aging of the reactor head closure stud bolting components will be effectively managed such that intended functions are maintained during the subsequent period of extended operation.

2. Inservice Inspections of the NMP1 reactor head closure studs, nuts, bushings, and washers were performed during the Fourth Inservice Inspection Interval from August 2009 through August 2019. Volumetric examination of the reactor head closure studs was performed during the Spring 2011, 2013, and 2017 refueling outages. The results of the volumetric examination were acceptable. Visual examination of the reactor head closure nuts and washers was also performed during the 2011, 2013, and 2017 refueling outages. Visual examination of the reactor head closure bushings was performed during the Spring 2013 and 2017 refueling outages. The results of the visual examination were acceptable.

This summary of NMP1 Inservice Inspection results during the Fourth Inservice Inspection Interval from August 2009 through August 2019 provides objective evidence that age-related degradation of the reactor head closure stud bolting components is being effectively managed and that examinations are performed utilizing techniques specified in ASME Code Section XI which have been demonstrated to be capable of identifying cracking and loss of material.

The operating experience relative to the Reactor Head Closure Stud Bolting aging management program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Reactor Head Closure Stud Bolting aging management program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Reactor Head Closure Stud Bolting aging management program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing Reactor Head Closure Stud Bolting aging management program provides reasonable assurance that the cracking and loss of material aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.4 BWR Vessel ID Attachment Welds

Program Description

The BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that manages cracking of reactor vessel internal attachment welds due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or cyclic loading in a reactor coolant environment. The program relies on visual techniques to detect and size cracks. Inspections and evaluations follow the guidelines of BWRVIP-48-A, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," in lieu of the requirements within ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-2, per NRC-approved relief request I5R-03 (ADAMS Accession No. ML18318A275). The potential for cracking due to SCC or IGSCC is mitigated by maintaining high water purity as described in the Water Chemistry (B.2.1.2) program. The scope of the program includes attachment welds for the steam dryer support brackets, guide rod brackets, feedwater sparger brackets, and the surveillance sample holder brackets.

Indications are evaluated consistent with ASME Code, Section XI, Subsections IWB-3500 and IWB-3600 and the additional guidance provided in BWRVIP-48-A. If flaws are found, the condition is entered into the corrective action program and the scope of the inspection is expanded in accordance with the guidance provided in BWRVIP-48-A. Repair and replacement procedures comply with the requirements of ASME Code, Section XI. If the flaw exceeds the requirements of IWB-3600, repair and replacement is performed consistent with the requirements of ASME Code, Section XI, Subsection IWA-4000.

The BWR Vessel ID Attachment Welds program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are applicable to all Constellation BWR plants. The equivalent BWR Vessel ID Attachment Welds program for Peach Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the BWR Vessel ID Attachment Welds program will adequately manage the effects of aging such that the intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The BWR Vessel ID Attachment Welds aging management program is consistent with the ten elements of aging management program XI.M4, "BWR Vessel ID Attachment Welds," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Vessel ID Attachment Welds program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. Aging management program effectiveness reviews were performed for the BWR Vessel ID Attachment Welds program in 2019 and 2025. The purpose of the reviews was to verify that the program is effectively identifying and addressing any indications of cracking due to SCC, IGSCC, or cyclic loading. The reviews included audits of the program schedule for consistency with BWRVIP-48-A, review of inspection records, and review of relevant entries in the corrective actions program to ensure that issues potentially adverse to quality are being driven to resolution.

The reviews concluded that the inspection methods being implemented in the program are effective in identifying aging effects for BWR vessel interior attachment welds. Inspections are performed in accordance with the guidelines of BWRVIP-48-A. If flaws are discovered, the conditions are entered into the corrective actions program and the inspection scope is expanded in accordance with BWRVIP-48-A. Continued implementation of the BWR Vessel ID Attachment Welds aging management program during the subsequent period of extended operation will provide assurance that the reactor vessel interior attachment welds will continue to perform their intended functions.

This operating experience example provides objective evidence that self-assessments of the aging management program are performed to support continuous improvement.

2. The upper and lower surveillance sample holder bracket attachment welds were examined by the VT-1 method during the 2017 refueling outage (030, 210, 300 azimuthal locations). The inspection included coverage of the adjacent weld heat affected zones. The inspections did not identify any indications of cracking.

The feedwater sparger bracket attachment welds were inspected by the EVT-1 method during the 2013 and 2023 refueling outages. The inspections included coverage of the adjacent heat affected zones. The inspections did not identify any indications of cracking. The 2013 and 2023 refueling outages also included VT-1/VT-3 inspections of the guide rod bracket attachment welds and heat affected zones. No relevant indications were identified for the guide rod brackets.

This example demonstrates how condition monitoring in accordance with BWRVIP-48-A guidelines is used to manage cracking in reactor vessel interior attachment welds. To date, indications of cracking have not been identified in the attachment welds for the surveillance sample brackets, feedwater sparger brackets, or the guide rod brackets. Continued implementation of the BWR Vessel ID Attachment Welds aging management program will assure that the

components will continue to perform their intended function during the subsequent period of extended operation.

3. During EVT-1 inspections of the steam dryer support bracket attachment welds in the 2011 refueling outage, relevant indications were identified in three of the four brackets. The indications are indicative of IGSCC. The four steam dryer brackets were reinspected during the 2013, 2015, 2017, and 2019 refueling outages by using EVT-1 and/or a qualified ultrasonic testing (UT) tool. The inspections included coverage of the heat affected zones adjacent to the attachment welds. The UT inspection methodology identified indications of cracking in each of the four brackets. Results from these inspections were entered into the corrective actions program where they were evaluated and dispositioned. Continued service without repair of the steam dryer support brackets is justified by a flaw evaluation performed in accordance with ASME Code, Section XI.

The 2021 inspection of the steam dryer support bracket attachment welds was performed by using EVT-1 as well as the qualified UT tool. The 2021 UT inspection identified one additional indication and cases of increased indication size in comparison to previous inspections. Inspection results were entered into the corrective action program where they were evaluated and dispositioned. Flaw evaluations justified continued operation without repair for two additional cycles.

Reinspection of the steam dryer support bracket attachment welds occurred during the 2025 outage by EVT-1 and UT. The results of the inspections were entered into the corrective actions program. Several cases of increased indication sizing were reported. All cracking observed is in the stainless-steel, nonsafety-related lug side of the attachment weld (i.e., no penetration into the Inconel 182 attachment weld material or reactor low alloy steel). Flaw evaluations performed in accordance with BWRVIP-48-A and ASME Code, Section XI justified continued operation without repair for two additional cycles. The next EVT-1 inspections for the steam dryer support bracket attachment welds are scheduled for the 2027 refueling outage. The next UT inspection of the steam dryer support bracket attachment welds is scheduled for the 2029 refueling outage.

The 2025 steam dryer support bracket attachment weld UT inspections also identified several indications of non-surface connected weld discontinuity in the support bracket base material. The construction code for the steam dryer support bracket attachment welds aligns with the original reactor pressure vessel construction code (ASME Section 1, 1962 Edition), which does not directly address internal attachment weld discontinuities in the attached component's base metal. Since no direct criteria was located in the original construction code, the weld joint efficiency guidance of ASME Code, Section VIII, Division 1 was used. The limiting indication of weld discontinuity met the minimum required weld joint efficiency. Accordingly, the indications of weld discontinuity in the support brackets were considered non-relevant indications.

This operating experience provides objective evidence that inspections of the steam dryer support brackets are being conducted in accordance with

BWRVIP-48-A guidelines and that the inspections are effective in identifying cracking indications prior to loss of intended function. This example also demonstrates that the corrective action program is used effectively to evaluate, monitor, and trend conditions adverse to quality. Further, this operating experience shows that flaws are being evaluated in accordance with ASME Code, Section XI guidance and that the results are used to inform inspection methodologies and periodicities.

The operating experience relative to the BWR Vessel ID Attachment Welds program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including stress corrosion cracking, intergranular stress corrosion cracking, and cracking due to cyclic loading. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Vessel ID Attachment Welds program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Vessel ID Attachment Welds program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing BWR Vessel ID Attachment Welds program provides reasonable assurance that the cracking aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.5 BWR Stress Corrosion Cracking

Program Description

The BWR Stress Corrosion Cracking aging management program is an existing condition monitoring and mitigative program that manages cracking due to intergranular stress corrosion cracking (IGSCC) for all BWR piping and piping welds made of austenitic stainless steel and nickel alloy that are four inches or larger in nominal diameter containing reactor coolant at a temperature above 93 degrees C (200 degrees F) during power operation, regardless of code classification. The program implements the measures delineated in NUREG-0313, Revision 2, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," and NRC Generic Letter (GL) 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," and its Supplement 1. The program includes preventive measures to mitigate IGSCC and inspection and flaw evaluation to monitor IGSCC and its effects. Most of the Reactor Water Cleanup (RWCU) System piping and welds, outboard of the containment isolation valves, is excluded from this program in accordance with the guidance contained in NRC GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," and GL 88-01 including Supplement 1. Two RWCU System piping welds outboard of the second isolation valve were identified with pressure boundary leaks. Both welds have been repaired by a full structural weld overlay and have been reclassified in accordance with NRC GL 88-01 to IGSCC Category E, which requires inspection under this program.

Reactor coolant water chemistry is controlled and monitored in accordance with EPRI guidelines to maintain high water purity and reduce susceptibility to stress corrosion cracking (SCC) or IGSCC as described in the Water Chemistry (B.2.1.2) program. Hydrogen water chemistry and noble metal chemical addition have been implemented to further reduce susceptibility of the piping systems exposed to reactor coolant to SCC or IGSCC.

The program addresses the management of crack initiation and growth due to IGSCC in the piping, welds, and components through the implementation of the ISI program in accordance with ASME Code, Section XI. Inservice inspections, performed as augmented requirements of the Section XI ISI program, ensure that aging effects are identified and repaired before the loss of intended function of in scope components. The inspection frequency for welds classified in accordance with NRC GL 88-01 as IGSCC Category B through G is per the recommendations provided in the NRC-approved BWRVIP-75-A, "BWR Vessel and Internals Project, Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," for normal water chemistry conditions. Welds classified as IGSCC Category A may be inspected at a frequency in accordance with ASME Section XI, including the Code Case N-716-1, "Alternative Piping Classification and Examination Requirements," risk-informed inservice inspection (RI-ISI) program.

Inspection and flaw evaluation is conducted in accordance with the ASME Code, Section XI. If a flaw exceeds the applicable acceptance standards, then the condition is entered into the corrective action program and an analytical evaluation may be performed to determine its acceptability for continued service without repair or replacement. Evaluations are performed using the applicable crack growth rate

provided by ASME Code, Section XI. BWRVIP-14-A, BWRVIP-59-A, BWRVIP-62-A, and Code Case N-896 also provide approved guidelines that can be used for evaluating crack growth in stainless, nickel alloys, and low-alloy steels. In accordance with NRC GL 88-01, repair of an IGSCC flaw, or an evaluation performed to accept a flaw must be approved by the NRC before resuming power operation.

The guidance for replacement, weld overlay repair, and stress improvement is provided in several industry documents, including NRC GL 88-01, NUREG-0313, Revision 2, ASME Code, Section XI, Subsection IWA-4000, and approved code cases.

The BWR Stress Corrosion Cracking program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are applicable to all Constellation BWR plants. The equivalent BWR Stress Corrosion Cracking program for Peach Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the BWR Stress Corrosion Cracking program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The BWR Stress Corrosion Cracking aging management program is consistent with the ten elements of aging management program XI.M7, “BWR Stress Corrosion Cracking,” specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Stress Corrosion Cracking program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. Aging management program effectiveness reviews were performed for the BWR Stress Corrosion Cracking program in 2019 and 2025. The program effectiveness reviews included the following objectives: (1) verifying that aging effects are detected in sufficient time to implement corrective actions before there is a loss of intended function, (2) verifying that the corrective actions program is used effectively for cause evaluation and prevention of recurrence, (3) verifying that industry and plant operating experience are used to inform the aging

management programs, and (4) verifying that license renewal commitments for the first period of extended operation are appropriately maintained. Combined reviews were performed for all ASME Code, Section XI related aging management programs. The effectiveness reviews concluded that the BWR Stress Corrosion Cracking aging management program is effectively meeting inspection requirements and is effectively using the corrective actions program to document and evaluate conditions adverse to quality.

This operating experience provides objective evidence that the current BWR Stress Corrosion Cracking program is being effectively implemented during the first period of extended operation. Continued implementation of the BWR Stress Corrosion Cracking program will ensure that the cracking aging effect is effectively managed during the subsequent period of extended operation.

2. Welds 33-FW-22 and 33-FW-23A are in the Reactor Water Cleanup System and are both nonsafety-related, non-ASME Section XI welds that are located outboard of the primary containment isolation valves. Weld 33-FW-22 joins carbon steel RWCU System piping with a 304 stainless steel heat exchanger inlet nozzle, while weld 33-FW-23A joins two stainless steel nozzles. Weld 33-FW-22 was repaired by weld overlay in 1997 due to the identification of a through-wall leak. Similarly, weld 33-FW-23A was repaired by weld overlay in 2004 due to a through-wall leak. Both welds have been reclassified as IGSCC category E. The welds are reinspected under the ISI program in accordance with the normal water chemistry (NWC) inspection frequency provided in BWRVIP-75-A.

Weld 33-FW-22 was inspected by ultrasonic testing (UT) during the 2013 refueling outage. The UT inspection identified the previous IGSCC indication and concluded that the indication within the base material did not propagate into the weld overlay. This weld was reinspected during the 2023 refueling outage. The previously recorded indication was observed without significant change.

Weld 33-FW-23A was inspected by UT during the 2011 and 2023 refueling outages. Both inspections observed the previously recorded indication without significant changes. No relevant indications were reported in the weld overlay material.

This operating experience example provides objective evidence that the industry guidelines per NRC GL 88-01, NUREG-0313, Revision 2, and BWRVIP-75-A are effectively applied to monitor the condition of welds within the scope of the program.

3. During the 2023 refueling outage, automated UT inspections were performed on the nozzle-to-safe end dissimilar metal weld 32-WD-208 (recirculation discharge nozzle N2E). During this inspection, one relevant indication was recorded. The indication was axially oriented and located in the dissimilar metal weld and adjacent safe end material. The indication was inner diameter connected with attributes indicative of IGSCC. The inspection results were entered into the corrective action program, where the issue was evaluated in accordance with the requirements of ASME Code, Section XI and the guidelines of BWRVIP-75-A.

The edition of ASME Code, Section XI applicable to NMP1 during the fifth ISI interval (2013 Edition) does not contain requirements for nickel alloy weld overlays; however, nickel alloy overlays have been applied to other reactor pressure vessel dissimilar metal welds in BWRs using alternative requirements. NMP1 submitted Relief Request I5R-11 to use the guidance of Code Case N-740-2 and ASME Code, Section XI, Nonmandatory Appendix Q for application of a weld overlay. The relief request was approved by the NRC on the basis that the proposed alternative provided an acceptable level of quality and safety, and that the structural integrity and leak tightness of the overlaid weld would be maintained until the 2025 refueling outage (ADAMS Accession No. ML23156A682). NMP1 completed a leakage barrier weld overlay to provide a temporary repair to eliminate the risk of through-wall leakage that could result from continued growth of the IGSCC flaw. The repair used IGSCC resistant Alloy 52M filler material. Additionally, a flaw evaluation was performed to justify the adequacy of the repair for one cycle of operation.

In the 2025 refueling outage, a full structural weld overlay (FSWOL) repair was applied to 32-WD-208. In lieu of performing the repair activity in accordance with IWA-4000, Relief Request I5R-12 was submitted which proposed the alternative rules of ASME Code Case N-740-2. Code Case N-740-2, provides general requirements, design, installation, and examination criteria for FSWOLs using Alloy 52M weld filler materials. The proposed alternative was approved by the NRC (ADAMS Accession No. ML24145A186). Indications identified during the non-destructive testing of the completed FSWOL repair were entered into the corrective action program where they were evaluated and dispositioned.

This operating experience example provides objective evidence that the industry guidelines per NRC GL 88-01, NUREG-0313, Revision 2, and BWRVIP-75-A are effectively applied to monitor the condition of welds within the scope of the program. Additionally, this operating experience example shows that the corrective action program is used to document conditions adverse to quality and facilitate repairs of any identified flaws.

The operating experience relative to the BWR Stress Corrosion Cracking program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Stress Corrosion Cracking program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Stress Corrosion Cracking program will effectively manage the effects of aging and initiate corrective action prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing BWR Stress Corrosion Cracking program provides reasonable assurance that the cracking aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.6 BWR Penetrations

Program Description

The BWR Penetrations aging management program is an existing condition monitoring program that manages the aging effect of cracking due to cyclic loading, intergranular stress corrosion cracking, or stress corrosion cracking of the BWR instrumentation penetrations, control rod drive (CRD) housing and incore-monitoring housing (ICMH) penetrations, and the standby liquid control (SLC)/core plate differential pressure (ΔP) penetration exposed to a reactor coolant environment. The program is implemented through station procedures that provide for mitigation of cracking through management of water chemistry and condition monitoring through examinations of reactor vessel penetration and nozzle welds. The examination categories include volumetric, surface, and visual examination methods.

In addition to the requirements of ASME Code, Section XI, Subsection IWB, the BWR Penetrations program incorporates the inspection and flaw evaluation recommendations of BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines," and the recommendations for reactor water chemistry as described in the Water Chemistry (B.2.1.2) program.

The BWR Penetrations program monitors the effects of cracking due to cyclic loading, stress corrosion cracking (SCC), and intergranular stress corrosion cracking (IGSCC) by requiring inspections of the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate ΔP penetration as part of the ISI program per the requirements of ASME Code, Section XI, Table IWB-2500-1. A description of the ISI program, including the controlling edition of ASME Code, Section XI, is provided in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program. During each refueling outage, a visual inspection (VT-2) of the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and SLC/core plate ΔP penetration is performed during the reactor coolant pressure boundary system leakage test. Abnormal or unexpected findings are entered into the corrective action program for evaluation and resolution.

When the reactor pressure vessel lower plenum area is accessible during normal reactor refueling activities, visual inspections are performed to the extent practical per BWRVIP-47-A guidelines. Inspections are performed in accordance with the guidelines of BWRVIP-49-A for the instrument penetrations, BWRVIP-47-A for the CRD housing and ICMH housing penetrations, and BWRVIP-27-A for the SLC/core plate ΔP penetration. The guidelines of BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A provide information on the type of penetrations, evaluate their susceptibility and consequences of failure, and define the inspection strategy to ensure safe operation.

The BWR Penetrations program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are applicable to all Constellation BWR plants. The equivalent BWR Penetrations program for Peach Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2

and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the BWR Penetrations program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The BWR Penetrations aging management program is consistent with the ten elements of aging management program XI.M8, “BWR Penetrations,” specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Penetrations program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. Aging management program effectiveness reviews were performed for the BWR Penetrations program in 2019 and 2025. The purpose of the effectiveness reviews was to verify that the program is effectively detecting aging effects with sufficient time to implement corrective actions. The AMP effectiveness reviews considered a sample of tests, inspections, and associated issue reports (IRs) to verify that implementation activities were performed in accordance with program requirements. Combined reviews were performed for all programs that involve BWRVIP activities. The assessments concluded that the program is effectively managing the aging effects of in scope SSCs as no loss of intended function has occurred during the period of extended operation for this program. The program effectiveness review also concluded that appropriate BWRVIP guidance is being implemented.

This operating experience provides objective evidence that the current BWR Penetrations program is being effectively implemented during the first period of extended operation. Continued implementation of the BWR Penetrations program will ensure that the aging effect of cracking due to SCC or IGSCC is effectively managed during the subsequent period of extended operation.

2. In the NMP1 first license renewal application, a commitment was made to complete the baseline inspections of BWRVIP-47-A during the first period of extended operation. These inspections were completed during refueling outages between 2011 and 2021. The alignment pin to core plate weld (FS/GT ARPIN-1) integrity was confirmed by either a VT-3 visual inspection or by removal and installation of the fuel support casting. Control rod drive tube sleeve to alignment

pin lug welds (CRGT-1) were inspected using the VT-3 method. Control rod drive tube body to sleeve welds (CRGT-3) were inspected using the EVT-1 method. No new indications of cracking or other material condition issues were identified during these baseline inspections.

While not specifically related to bottom head penetrations, the baseline inspections related to the CRD guide tube are intended to identify any generic indications of cracking in the lower plenum components and inform any future adjustments to inspection requirements. This operating experience provides objective evidence that NMP1 performs opportunistic inspections of components in the lower plenum per BWRVIP-47-A when access is available.

3. During the 2009 refueling outage, the SLC/core plate ΔP penetration-to-safe end weld and the entire safe end extension were inspected by using the UT method as required by ASME Code, Section XI, Table IWB-2500-1 and recommended by BWRVIP-27-A. No cracking or other material condition concerns were identified during these inspections. The SLC/core plate ΔP penetration-to-safe end weld and the safe end extension were reinspected via UT during the 2019 refueling outage. No relevant indications were identified during this inspection.

This operating experience provides objective evidence that the inspections required by BWRVIP-27-A are being implemented using the recommended methods for identifying cracking. Future inspections are scheduled per BWRVIP-27-A recommendations.

4. A reactor coolant pressure boundary system leakage test is performed each refueling outage for NMP1. During the system leakage test, the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate ΔP penetration are inspected by using the VT-2 method as recommended by BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A, respectively. No leakage from these components has been identified since 2001, which was the most recent instance of under vessel stub tube leakage.

This operating experience example provides objective evidence that the inspections required by BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A are being implemented using the methods recommended for identifying cracking. Additionally, this operating experience shows that previously performed stub tube roll repairs have remained leak tight during the first period of extended operation.

5. In 2017, a Constellation fleet BWR identified instrument nozzle leakage during the Class 1 system leakage test at the end of a refueling outage. Investigation determined the most probable root cause to be IGSCC originating from a construction defect in the Alloy 82 overlay cladding which created a creviced environment where cracking could initiate. A half nozzle repair was performed, which entailed machining a portion of the degraded nozzle from the vessel penetration and welding a new nozzle to the outside of the vessel wall. In response to this operating experience, NMP1 and other Constellation fleet BWRs scheduled supplemental visual inspections each outage for instrument nozzles to identify any potential leakage early in the outage window. During the fifth ISI interval, NMP1 scheduled these supplemental inspections such that each instrument nozzle is inspected at least every other refueling outage. Supplemental visual inspections were performed for the instrument nozzles

during the 2021, 2023, and 2025 refueling outages. For these inspections, insulation was removed to perform a bare metal visual examination of the nozzle and nozzle-to-vessel interface. These inspections did not identify any instrument nozzle leakage.

This example provides objective evidence that NMP1 is responsive to industry operating experience.

The operating experience relative to the BWR Penetrations program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Penetrations program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Penetrations program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing BWR Penetrations program provides reasonable assurance that the cracking aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.7 BWR Vessel Internals

Program Description

The BWR Vessel Internals aging management program is an existing condition monitoring and mitigative program that manages aging of the reactor vessel internals in accordance with the requirements of ASME Code, Section XI and Boiling Water Reactor Vessels and Internals Project (BWRVIP) reports. The program manages the aging effects of cracking, loss of material, and loss of fracture toughness of vessel internal components in a reactor coolant environment. The program includes inspection and flaw evaluation in conformance with the guidelines of applicable BWRVIP reports and ASME Code, Section XI. The program also mitigates these aging effects by managing water chemistry per the Water Chemistry (B.2.1.2) program. The BWR Vessel Internals program includes periodic inspections of components fabricated from X-750 material to provide for timely identification of cracks that may be indicative of degradation due to thermal aging and neutron irradiation embrittlement. Precipitation-hardened (PH) martensitic stainless steel (e.g., 15-5 and 17-4 PH steel), and martensitic stainless steel (e.g., Type 403, 410, 431 steel) are not used within the reactor vessel internal components.

The BWR Vessel Internals program follows applicable and approved BWRVIP guidelines for inspection, evaluation, and repair recommendations for the components listed. When new or revised guidance is issued, it will be implemented in accordance with BWRVIP-94, Revision 4, "Program Implementation Guide," and NEI 03-08, "Guideline for the Management of Material Issues," per fleet procedures. If new or revised guidelines include revisions to NRC-approved BWRVIP guidelines, and the revised guidelines are less conservative than those approved by the NRC, these less conservative guidelines shall be implemented only after the NRC reviews and approves the changes. Additionally, the program allows for deviation from BWRVIP examination recommendations based on the requirements of NEI 03-08.

The program currently includes the following BWRVIP guidelines for inspection, evaluation, and repair of the components listed.

Core Shroud: Inspections are performed in accordance with BWRVIP-76, Revision 1-A, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines." The NMP1 shroud is a repaired shroud with tie rods installed to structurally replace H1 through H7 and vertical weld clamps installed to structurally replace V9 and V10. The repair design criteria in the approved revision of BWRVIP-02 at the time of repair were utilized in preparing the repair plan. The repair design criteria in BWRVIP-02-A, Revision 2, "BWR Core Shroud Repair Design Criteria," would be utilized in preparing any future repair plans for the core shroud.

Core Plate: The NMP1 core plate has been modified with four wedge assemblies that provide lateral seismic stability. Therefore, in accordance with BWRVIP-25, Revision 1-A, "BWR Core Plate Inspection and Flaw Evaluation Guidelines," a plant-specific evaluation was performed that concluded inspections of the core plate rim hold-down bolts and the core plate-to-rim welds are not required. The repair design criteria in BWRVIP-50-A, "Top Guide/Core Plate Repair Design Criteria," would be utilized in preparing any future repair plans for the core plate.

Core Spray: Inspections and evaluations are performed in accordance with BWRVIP-18, Revision 2-A, “BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines.” BWRVIP-16-A, “Internal Core Spray Piping and Sparger Replacement Design Criteria,” and BWRVIP-19-A, “Internal Core Spray Piping and Sparger Repair Design Criteria,” would be used in preparing any future repair plans for core spray system components that are internal to the reactor vessel.

Shroud Support: Inspections and evaluations are performed in accordance with BWRVIP-38, “BWR Shroud Support Inspection and Flaw Evaluation Guidelines.” The repair design criteria in BWRVIP-52-A, “Shroud Support and Vessel Bracket Repair Design Criteria,” would be utilized in preparing a repair plan for the core shroud support.

Jet Pump Assembly: The NMP1 reactor vessel internals design does not include jet pump assemblies. BWRVIP guidance for inspection, evaluation, and repair of jet pump assemblies does not apply.

LPCI Coupling: The NMP1 reactor vessel internals design does not include a low-pressure coolant injection (LPCI) coupling. BWRVIP guidance for inspections, flaw evaluations, and repairs of LPCI couplings does not apply.

Top Guide: Inspections and evaluations are performed in accordance with BWRVIP-26-A, “BWR Top Guide Inspection and Flaw Evaluation Guidelines,” and BWRVIP-183-A, “Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines.” The repair design criteria in BWRVIP-50-A would be utilized in preparing future repair plans for the top guide. Nine Mile Point Nuclear Station, Unit 1 has four top guide hold-down assemblies installed. In accordance with BWRVIP-26-A, two hold-down assemblies are inspected every other cycle (180° apart, VT-1 inspection). Accordingly, each hold down assembly is inspected once in four cycles. Nine Mile Point Nuclear Station, Unit 1 currently has 67 relevant indications that have been evaluated for operation through 49 EFPY. Ultrasonic testing (UT) of 100 percent of the top guide was performed in 2021, which included all grid beam and beam-to-beam crevice slots. All previously identified indications showed no growth and no new flaws were identified. The four most limiting flaw indications were UT inspected in 2025, with no new growth identified. Existing top guide flaws are re-inspected on a frequency not to exceed six years. For ease of inspections, 100 percent of the top guide grid beams are inspected every six years. This ensures that the top guide locations that have high neutron fluence exceeding the irradiation-assisted stress corrosion cracking (IASCC) threshold are being inspected. The inspection schedule will continue to meet or exceed the requirements of BWRVIP-183-A through the subsequent period of extended operation.

Control Rod Drive Housing and Lower Plenum Components: Inspections are performed when components are accessible and evaluations are performed if indications are identified, in accordance with BWRVIP-47-A, “BWR Lower Plenum Inspection and Flaw Evaluation Guidelines.” The inspections required by BWRVIP-47-A relative to CRD housings, instrument penetrations, and components within the lower plenum are further discussed in the BWR Penetrations (B.2.1.6) aging management program. The repair design criteria in BWRVIP-55-A, “Lower Plenum Repair Design Criteria,” and BWRVIP-58-A, “CRD Internal Access Weld

Repair,” would be utilized in preparing a repair plan for the control rod drive housings and instrument penetrations.

Steam Dryer: Inspections and flaw evaluations are performed in accordance with BWRVIP-139, Revision 1-A, “Steam Dryer Inspection and Flaw Evaluation Guidelines.” The NMP1 steam dryer is original plant equipment and has been repaired previously (e.g., bolted repairs, reinforcement clips, crack arrest holes). BWRVIP-181-A, “Steam Dryer Repair Design Criteria,” will be utilized in preparing repair plans for the steam dryer.

Access Hole Covers: The NMP1 reactor internals design does not include access hole covers. BWRVIP guidance for inspection, evaluation, and repair of access hole covers does not apply.

The BWR Vessel Internals program specifies the necessary examinations to be performed during each outage based on the BWRVIP guidelines. BWRVIP-03, “Reactor Pressure Vessel and Internals Examination Guidelines,” specifies VT-1 and EVT-1 examinations to detect surface discontinuities and imperfections such as cracks. Volumetric examinations are performed as specified by BWRVIP guidelines. VT-3 examinations are specified to determine the general condition of components by verifying parameters, such as clearances and displacements, and by detecting discontinuities and imperfections, such as loss of integrity of bolted or welded connections, or loose or missing parts, debris, corrosion, wear, or erosion. The examination procedures also identify the type and location of examination required for each component, as well as the basis for the examination.

Evaluations of reactor vessel internal components determined that supplemental inspections in addition to the existing BWRVIP examination guidelines are not necessary to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement and cracking due to IASCC during the subsequent period of extended operation. This determination is based on neutron fluence, cracking susceptibility, fracture toughness, and consequences of cracking or failure of the reactor vessel internal components.

The program allows for deviation from BWRVIP examination recommendations based on the requirements of NEI 03-08. Any relief request from the requirements of ASME Code, Section XI is submitted to the NRC for approval in accordance with 10 CFR 50.55a.

Evaluation of indications or flaws identified by examination is conducted consistent with the applicable and approved BWRVIP guideline or ASME Code, Section XI, as appropriate for the affected component. Additional general guidelines per BWRVIP-14-A, BWRVIP-59-A, and BWRVIP-60-A are applied for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels. Repair and replacement activities, if needed, are performed in accordance with ASME Code, Section XI requirements for code components, consistent with the recommendations of the appropriate BWRVIP repair and replacement guidelines. For nickel alloy repairs, BWRVIP-44-A, “Underwater Weld Repair of Nickel Alloy Reactor Vessel Internals,” would be used for weld repairs of irradiated structural components.

BWRVIP License Renewal Applicant Action Items listed in the NRC Safety Evaluation Reports for BWRVIP reports are addressed in Appendix C.

The BWR Vessel Internals program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are applicable to all Constellation BWR plants. The equivalent BWR Vessel Internals program for Peach Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the BWR Vessel Internals program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The BWR Vessel Internals aging management program will be consistent with the ten elements of aging management program XI.M9, “BWR Vessel Internals,” specified in NUREG-2191.

There are a few differences in the BWRVIP report revisions recommended in NUREG-2191 and those being implemented at NMP1. These include BWRVIP-03, Revision 21 versus BWRVIP-03, Revision 19, and BWRVIP-100, Revision 2, “Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Internal Components,” versus BWRVIP-100, Revision 1-A. These deviations are deemed acceptable as the NRC determined future revisions of BWRVIP-03 do not need Safety Evaluations and BWRVIP-100 was updated to account for non-conservatism in the approved version and has subsequently been approved by the NRC.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the BWR Vessel Internals program will be enhanced to:

1. Develop a justification for operation of the top guide through the subsequent period of extended operation by means of a flaw evaluation, consistent with BWRVIP-94, Revision 4; BWRVIP-183-A; BWRVIP-100, Revision 2-A; BWRVIP-14-A; and EPRI Letter 2025-057; as applicable, and develop the necessary inspections and inspection frequencies to validate that the top guide can perform its intended function through the subsequent period of extended operation. Revise procedures governing the top guide inspections to reflect the flaw evaluation, necessary inspections, and inspection frequencies. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Corrective Actions (Element 7)**
2. Develop a justification for the service life of the core shroud tie-rod X-750 subcomponents through the subsequent period of extended operation, consistent with BWRVIP-94, Revision 4, which may include supplemental inspections,

inspection frequencies, and technical evaluations to validate that the core shroud tie-rod X-750 subcomponents can perform their intended function through the subsequent period of extended operation. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Corrective Actions (Element 7)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Vessel Internals program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an effectiveness review was performed on the existing BWR Vessel Internals aging management program. The purpose of the effectiveness review was to verify that the existing aging management program is being effectively implemented in the first license renewal period of extended operation to identify and address indications of cracking and other aging effects associated with BWR reactor vessel internal components. All BWRVIP documents listed as part of the associated license renewal commitments were reviewed, as well as implementation schedule. The aging management program effectiveness review included a sampling review of component NDE examination reports, flaw evaluations, and issues in the corrective action program associated with BWR reactor vessel internals including core spray spargers and piping, core shroud, core plate, top guide, and the steam dryer.

The review identified that license renewal commitments are being implemented, and inspections are being performed in accordance with BWRVIP guidelines, with no gaps identified. This review found that inspection findings which exceed acceptance criteria are evaluated and resolved in a timely manner. This review also revealed that indications of cracking or other aging effects which were previously identified during NDE inspections were re-inspected, results entered in the corrective action program and evaluated for continued use in accordance with the appropriate BWRVIP guidelines. The performance of the NDE inspections, flaw evaluations, and proper re-inspection and scope expansion has resulted in the effective implementation of this aging management program. The program effectiveness review also verified the recommendations of the BWRVIP documents are being implemented.

This operating experience provides objective evidence that the current BWR Vessel Internals program is being effectively implemented during the first period of extended operation. Continued implementation of the BWR Vessel Internals aging management program will effectively manage the aging effects of cracking, loss of material, loss of preload, and loss of fracture toughness in BWR reactor vessel internal components to assure that these components will continue to perform their intended functions during the subsequent period of extended operation.

2. During the 2009 refueling outage, it was discovered that the guide tube and fuel support alignment (anti-rotation) pin at core location 22-23 moved and appeared to be loose. Upon discovery, a corrective action program issue report was initiated, and an engineering evaluation was performed. The evaluation concluded that the pin was acceptable for use without repair as it continued to provide its function of preventing rotation of the guide tube and orificed fuel support during installation. The evaluation also concluded that the risk of the pin becoming a loose part was low. Procedural revisions were developed to add caution statements regarding the pin when removing the orificed fuel support and control rod guide tube at this location. A subsequent opportunistic VT-3 inspection of the pin was performed during the 2021 refueling outage, which identified no change in the condition of the pin. The results of this inspection were documented in the corrective action program.

This operating experience example provides objective evidence that opportunistic inspections of lower plenum components are completed when accessible. This example also shows that the corrective action program is being used effectively to evaluate conditions adverse to quality.

3. During the 2015 refueling outage, NMP1 performed a 100 percent UT inspection of the top guide. The inspection found no noted growth in the existing 79 indications. Of the 79 previously identified indications, only 65 were considered relevant. The remaining 14 indications were previously identified using techniques that were not demonstrated in accordance with BWRVIP-03. The use of BWRVIP-03 currently demonstrated techniques would not detect these indications and therefore are considered non-relevant. During the 2015 UT inspections, two new relevant flaws were identified emanating from the upper beam assembly slot. Indication #80 was approximately 1.16 inches in depth, while Indication #81 was 0.77 inches in depth. A corrective action program issue report was initiated, and a vendor evaluation was performed to justify operation until the next refueling outage. During the following refueling outage in 2017, reinspection of the indications showed depth changes, which were attributed to NDE uncertainty. Indication #80 was found to have a depth of 1.19 inches and Indication #81 was found to have a depth of 0.74 inches. Due to insignificant change in the indication, the previously completed flaw evaluation remained bounding for another cycle of operation. In 2018, it was identified that the vendor evaluation underpredicted the thermal stresses in the grid beams. A corrective action program issue report was initiated, and the flaw evaluation was updated, reducing margin within the flaw evaluation and resulting in a reduction of operating time. The relevant 67 flaws were evaluated using a fluence profile for 49 EFPY. Indications #80 and #81 were reinspected during the 2019 refueling outage, with no change in depth seen for either indication. Indications #80 and #81 were found to be bounding of all other flaws, which demonstrated acceptability of all locations through 2021. During the 2021 refueling outage, UT inspection was performed on 100 percent of the top guide. The inspections found that the previously identified relevant flaws did not show growth, and no new flaws were identified. The results of the inspection were captured in the corrective action program and the flaws were found to be bounded by the previously performed vendor analysis. A technical evaluation was performed to accept the UT results, and the evaluation showed acceptance for all flaws for at least four years. Inspections performed during the 2025 refueling outage of the

four most limiting flaws found no new growth and no new flaws. During the development of the NMP1 subsequent license renewal application, an unverified and undocumented assumption was identified in the flaw evaluation performed in 2018, which presented a potential non-conformance to BWRVIP-183-A. A corrective action program issue report was initiated, and corrective actions were taken to determine if the unverified crack growth rate was conservative and to produce a verified crack growth rate in accordance with BWRVIP-183-A. A new flaw evaluation was performed in 2026, which removed seismic loads applied during stress corrosion cracking (SCC) growth in the 2018 evaluation. These seismic loads were found to be overly conservative when applied to the SCC growth rate under normal operating conditions. Only sustained loads should have been included in crack growth rate calculations. The 2026 flaw evaluation determined all flaws to be acceptable for six years of operation and conformance with BWRVIP-183-A was met. Ultrasonic testing inspections of 100 percent of the top guide are scheduled to be performed in 2027.

This operating experience example provides objective evidence that inspections of the top guide are being performed in accordance with BWRVIP guidelines and that the inspections are effective in identifying cracking indications prior to loss of intended function. This example also demonstrates that the corrective action program is used effectively to evaluate, monitor, and trend conditions adverse to quality. Additionally, the operating experience shows that flaws are being evaluated in accordance with BWRVIP guidelines, and the results are used to determine reinspection frequencies.

4. In 1995, NMP1 installed core shroud tie rods for horizontal welds H1 through H7. These tie rods are designed to hold the shroud together in the event of a horizontal weld failure and are inspected on a 10-year frequency in accordance with BWRVIP-76, Revision 1-A. The inspections include tightness checks for the tie rods. The tightness checks look for metal-to-metal contact at two locations: the tie rod nut contact to the upper support and the tie rod clevis pin to the lower support hook. If a gap is identified at these two locations, measurements of the gaps are performed using visual inspection measurement techniques and an engineering review is required. Torquing may also be required if significant gaps are found. The 10-year shroud tie examination on all four tie rods was performed during the 2019 refueling outage. The individual tie rod gaps were found to be less than or equal to the total individual allowed gap of 0.063 inches. The combined average of the four tie rods, however, was found to exceed the allowable gap of 0.045 inches. The decision was made to perform torquing on the 166 degree tie rod to eliminate the 0.027 inch gap that was estimated from visual inspections. The torque sequence was only able to rotate the tie rod nut by 9 degrees, which was equivalent to a gap reduction of 0.005 inches. The as-left overall average of the four tie rods remained at 0.046 inches, which was slightly above the average allowable gap of 0.045 inches. A corrective action program issue report was initiated, and a vendor evaluation was performed. The evaluation found the condition to be acceptable and the tie rod design requirements continued to be met. Revised guidance was also provided to allow the individual tie rod gap to be allowable up to 0.070 inches, and the four tie rod average gap to be allowable up to 0.055 inches. Application of the revised guidance determined acceptability of the tie rods for an additional 10-year operating interval. Tie rod lower wedge and latch inspections remain required on

a two-year basis. If there are overall tie rod tightness changes after heatup and cooldown cycles, the tie rod lower wedge inspections would show a significant deviation complete to historical data. The lower wedge inspections provide redundancy which allows for confidence in the tie rod inspection program.

This operating experience example provides objective evidence that the core shroud horizontal weld repair hardware is being managed for aging in accordance with the applicable BWRVIP guidelines and specific recommendations from the tie rod repair vendor. This example also demonstrates that the corrective action program is being used effectively to identify, evaluate, and monitor conditions adverse to quality and perform corrective actions when needed.

5. During in-vessel visual inspections (IVVI) in the 2025 refueling outage, two indications were identified on the core spray sparger bracket at 332 degrees. One indication was found to be located in the shroud side heat affected zone (HAZ) on the right side of the upper sparger bracket attachment weld. The indication was found to be 0.205 inches in length. Another indication was identified on the upper core spray sparger tee box adjacent to the weld HAZ connecting the sparger bracket to the tee box. This indication was initially sized as 1.816 inches in length. The measurement was re-sized to 2.853 inches using known reference dimensions to determine the size of the indication without a physical measuring device. In effort to reduce the NDE uncertainty associated with the inspection, measurement by ruler was then performed, which resulted in the indication being sized as 2.5 inches. A corrective action program issue report was initiated for the indications, and a technical evaluation was performed. For the indication on the upper sparger bracket attachment weld, the condition was found to be acceptable for continued operation per BWRVIP-18, Revision 2-A. Reinspection will be required during the 2027 and 2029 refueling outages to determine the stability of the indication. If the shroud side HAZ indication remains unchanged during these inspections, then a 12-year inspection frequency will be used moving forward. For the indication on the upper core spray sparger tee box, a calculation was performed to evaluate the flaw for continued operation. The calculation determined that the tee box met the design criteria and was acceptable for an additional cycle of operation. Reinspection will be required during the 2027 refueling outage and beyond. Repair options are currently being evaluated using the life cycle management process.

This operating experience example provides objective evidence that the core spray sparger is being managed for aging in accordance with the applicable BWRVIP guidelines and that the inspections are effective in identifying cracking indications prior to loss of intended function. This example also demonstrates that the corrective action program is used effectively to evaluate and monitor conditions adverse to quality. Repairs are evaluated based upon inspection results. This example also demonstrates that the corrective action program is being used effectively to identify and evaluate conditions adverse to quality. Additionally, the operating experience shows that flaws are being evaluated in accordance with BWRVIP guidelines, and the results are used to determine reinspection frequencies.

6. In 2025, a focused area self-assessment (FASA) was performed for the NMP1 IVVI program. During this assessment, a gap was identified regarding the scheduling of inspections of core spray welds. Per BWRVIP-18, Revision 2-A, EVT-1 inspections of 100 percent of the core spray weld HAZ are required to be performed every 12 years. The full inspections were completed during the 2013 refueling outage and therefore were required to be performed again during the 2025 refueling outage. Only two of the eight S2 welds and one of the four S1 welds were inspected, leaving nine uninspected over the required interval. Upon identification of the gap, a corrective action program issue report was initiated. An engineering evaluation was performed to determine the impact of the missed inspections and continued operation until the next refueling outage was deemed acceptable. Per BWRVIP-94, Revision 4 and station procedures, a deviation disposition was written and submitted to the BWRVIP committee, and the NRC was notified. An extent of condition will also be performed, with completion by the third quarter of 2026.

This operating experience example provides objective evidence that NMP1 critically self-assessed the implementation of the BWR Vessel Internals program to identify deficiencies. This example also demonstrates that the corrective action program is effectively used to address deficiencies, determine the extent of condition, and implement appropriate actions to prevent recurrence. Additionally, industry guidelines are adhered to in effort to rectify deficiencies and timely notifications are made to interested parties.

The operating experience relative to the BWR Vessel Internals program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of material, and loss of fracture toughness of vessel internal components in a reactor coolant environment. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the BWR Vessel Internals program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the BWR Vessel Internals program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced BWR Vessel Internals program provides reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

Program Description

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide reasonable assurance that the intended functions of the reactor coolant pressure boundary CASS components (i.e., piping components, pump casings, and covers) with the potential for significant thermal aging embrittlement will be maintained.

The program will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, nickel content, and percent ferrite. Ferrite content is calculated by using the Hull's equivalent factors (described in NUREG/CR-4513, Revision 2). Screening for significance of thermal aging embrittlement is not required for ASME Code Class 1 CASS valve bodies because the existing ASME Code, Section XI inspection requirements are adequate for managing the aging effects of Class 1 valve bodies.

Components with the potential for significant thermal aging embrittlement will be managed through either qualified inspections, such as enhanced visual examination (EVT-1) or qualified ultrasonic testing methodology in accordance with ASME Code, Section XI, or a component-specific flaw tolerance evaluation. The program will not provide guidance on methods to mitigate thermal aging embrittlement. Inspections or evaluations are not required for components for which thermal aging embrittlement is not significant.

The reactor coolant system ASME Code Class 1 CASS components are maintained by inspecting and evaluating the extent of thermal aging embrittlement in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB. The Thermal Aging Embrittlement Cast Austenitic Stainless Steel (CASS) program augments the NMP1 ASME Section XI Inservice Inspection program and provides for monitoring, as required, of ASME Code Class 1 CASS components with service conditions above 250 degrees Celsius (482 degrees Fahrenheit) for loss of fracture toughness due to thermal aging embrittlement. NMP1 has reactor recirculation pump casings, covers, and suction elbows that are fabricated from CASS.

Thermal Aging Embrittlement of Cast Austenitic Stainless Steel program inspections, if required, will be based on ASME Code, Section XI, Table IWB-2411-1 and performed during each ISI interval. There are no ASME Code Class 2 CASS components within this program, therefore, Table IWC-2411-1 does not apply. The NMP1 ASME Code, Section XI program plans and directs the inspection schedules and the extent of the inspections in the program planning documents as required to provide timely detection of flaws. Abnormal or unacceptable results identified are entered into the corrective action program for evaluation and resolution.

Flaws detected in reactor coolant pressure boundary ASME Code Class 1 CASS components will be entered into the corrective action program and will be evaluated in accordance with the applicable procedures of ASME Code, Section XI. Nonmandatory Appendix C to the 2019 ASME Code, Section XI provides flaw evaluation procedures for CASS with ferrite content greater than or equal to 20

percent. This program may also use the flaw evaluation or flaw tolerance evaluation methods in the NRC-approved code cases that are documented in the latest revision of Regulatory Guide 1.147. Repairs and replacements are performed in accordance with ASME Code, Section XI, IWA-4000, in accordance with the NMP1 ISI program.

Reactor vessel internal components fabricated from CASS are not within the scope of this aging management program and are managed by the BWR Vessel Internals (B.2.1.7) program.

The new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program for Peach Bottom Atomic Power Station (PBAPS), has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC determined that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program will be consistent with the ten elements of aging management program XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program is a new program for NMP1. Industry operating experience that forms

the basis for this program is included in the operating experience element of the corresponding NUREG-2191 aging management program description. A search of the NMP1 corrective actions program and component history database was performed that covered the last 10 years of plant operation. No documented issues with the in-scope recirculation pump casings, covers, or elbows were identified. Additionally, the search did not identify any cases of loss of fracture toughness for the applicable material and environment combinations. This search also included a survey of past ISI records, which did not identify any instances of recirculation pump disassembly where visual inspection of the pump internals would be required.

2. Review of recent industry SLRAs identified the following relevant operating experience: During the Dresden Nuclear Power Station 2004, 2007, and 2019 refueling outages, scheduled 2A, 2B, and 3B reactor recirculation pump internal maintenance included visual (VT-3) inspections of the pump casings and covers for indications of cracking. The inspections were completed satisfactorily with no indications of cracking.

Peach Bottom Atomic Power Station performed visual inspections (VT-3) of reactor recirculation pump internals when the pumps were disassembled in the 1993, 2002, 2003, and 2007 refueling outages. The inspections found no recordable indications.

While not directly related to the management of thermal aging embrittlement, these opportunistic inspections of BWR fleet reactor recirculation pumps did not identify generic or industry wide concerns with cracking or otherwise poor material condition of the CASS recirculation pump casings or covers.

The operating experience relative to the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including thermal embrittlement and loss of fracture toughness. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will be performed to identify the areas that need improvement to maintain the quality performance of the program. The program will be informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.9 Flow-Accelerated Corrosion

Program Description

The Flow-Accelerated Corrosion aging management program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion (FAC) in carbon steel piping and piping components exposed to reactor coolant, steam, and treated water environments. The program is based on commitments made in response to NRC Generic Letter (GL) 89-08, “Erosion/Corrosion Induced Pipe Wall Thinning,” and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R4, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” for an effective FAC program.

CHECWORKS™ is used to predict component wear rates and remaining service life in the systems susceptible to FAC which provides reasonable assurance that structural integrity will be maintained between inspections. The model is revised if any changes in operating conditions or other factors that affect FAC (e.g., plant chemistry, power uprate) have occurred since the CHECWORKS™ model was last updated. Changes may also result from plant modifications that effect FAC behavior such as material changes, the addition of piping systems, piping system configuration changes, and the addition or replacement of in-line components. The CHECWORKS™ model is also refined by importing actual volumetric inspection data thickness measurements and re-running the wear rate analysis. This improves the predictive capability of the model to ensure that intended functions are maintained. Additionally, the program utilizes industry operating experience, plant experience, and engineering judgment of plant engineers to determine inspection locations.

Changes made to the CHECWORKS™ model are done 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.

When program software (i.e., CHECWORKS™ and/or Fleet FAC Trending Software) is revised or replaced and the update has potential to affect the calculation of component wear, wear rate, remaining component life, and/or next scheduled inspection, a review will be performed to verify and validate that the software calculates these parameters consistently with NSAC-202L. The verification and validation shall be documented and stored electronically such that it is available for review. Limited or minor revisions or replacements of the software (such as end user enhancements, reporting revisions or additions, etc.) with no potential to affect these calculations (as verified by software change logs, vendor release notes, etc.) are exempt from this requirement and require no documentation.

The program includes: (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analysis of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating and trending inspection data to determine the need for inspection sample expansion, repairs, or replacements,

and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

The program also manages wall thinning caused by mechanisms other than FAC such as cavitation, flashing, liquid droplet impingement and solid particle erosion in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms. FAC inspections and inspections performed for wall thinning caused by mechanisms other than FAC that do not meet acceptance criteria are evaluated in accordance with the corrective action program.

The Flow-Accelerated Corrosion program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are generally applicable to all Constellation plants, with certain aspects limited to operation beyond 60 years. The equivalent Flow-Accelerated Corrosion program for Peach Bottom Atomic Power Station, including the aspects of the program applicable to operation beyond 60 years, has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Flow-Accelerated Corrosion program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Flow-Accelerated Corrosion aging management program will be consistent with the ten elements of aging management program XI.M17, "Flow-Accelerated Corrosion," specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

1. The NUREG-2191 Chapter XI.M17, "Flow-Accelerated Corrosion," aging management program recommends that the minimum safety factor should not be less than 2.0 for determinations of erosion mechanism re-inspection intervals as discussed in EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack." Constellation uses a minimum safety factor of 1.5 for determinations of erosion mechanism re-inspection intervals. **Program Element Affected: Acceptance Criteria (Element 6)**

Justification for Exception

EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack," was published in 2015. The Constellation Erosion in Piping and Components (EPC) program considers the most recent industry guidance for program implementation. EPRI 3002023786, published in 2023, is the latest revision of the "Recommendations for an Effective Program Against Erosive Attack" and provides the industry consensus on the most effective means for managing wall thinning due to erosive mechanisms. The recommendation is that the safety factor for erosion should be 2.0 or greater unless a lower value is justified by the owner. Justification could be done by analysis, advanced

inspections, or other means. Cases where a safety factor for erosion less than 2.0 could be considered include:

- Locations where the degradation mechanism is well understood
- Locations where the time of degradation is known
- Locations where the UT inspection has been performed per recommendations and scans cover the total degradation area
- Locations where an advanced inspection technique such as Phased-Array UT has been used
- Locations where repeat inspections allow for more accurate trending
- Lines that are considered to have a low consequence of failure or are run-to failure
- Lines where operating conditions and operating history are known and have not undergone significant changes
- Locations with replaced piping materials that have higher hardness

The cases listed above allow for a safety factor for erosion less than 2.0; however, due to the non-linear nature of erosive attack, the minimum safety factor for erosion should never be less than 1.5. The Constellation EPC implementing procedure utilizes the above guidance for the determination of the safety factor to be used in erosion analysis. A similar approach was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the License Renewal of Clinton Power Station, Unit 1 (ADAMS Accession No. ML25238A215).

Enhancements

In the elements identified below, the Flow-Accelerated Corrosion program will be enhanced to:

1. Reassess infrequently used piping systems excluded from the scope of the program to ensure adequate bases exist to justify this exclusion for periods of extended operation beyond 60 years. **Program Element Affected: Detection of Aging Effects (Element 4)**
2. Reassess piping systems that were susceptible to cavitation but had lines excluded from the erosion program based on the 2 percent exclusion criterion to determine if the lines should be included in the erosion program based on the less than 100 hours of operation per year criteria. **Program Element Affected: Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Flow-Accelerated Corrosion program will be effective in assuring that intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed on the Flow-Accelerated Corrosion aging management program activities. The effectiveness review concluded that the NMP1 Flow-Accelerated Corrosion AMP is effectively managing aging effects of in scope SSCs to ensure a loss of function does not occur. Piping assessments and analysis are performed to determine critical locations; and to quantify the potential for FAC damage, then components are selected for inspection based on the analysis. On a biennial basis, during refueling outages, inspections are performed on the selected components to determine the extent of thinning at the selected locations. The inspection results are evaluated to determine the extent of wear, and the remaining service life is calculated for each component. Should the remaining service life be less than one operating cycle, then a condition report and work order would be generated to facilitate repair or replacement of that component. Should the wall thickness be degraded less than the design allowable minimum acceptable wall thickness, then additional inspections, if required, are performed to bound the area of thinning and processed in the corrective action program (CAP).

The results of the effectiveness review objectives were as follows:

- License renewal commitments were reviewed and found that all implementation activities have been completed or are being performed at the periodicity prescribed by the license renewal commitment. No changes to the scope or frequency of the program inspections have been made. A sample of issue reports written on SSCs within the scope of the program were reviewed and found that corrective actions were completed satisfactorily.
- Corrective actions, including cause evaluation and prevention of recurrence, were reviewed for timeliness. The review found that the cause of each failed acceptance criteria was known, the program procedures do not require a formal cause evaluation for every inspection failure, extent of condition reviews and inspections were completed as required, and fitness for service life evaluations were completed in the database and re-inspections were completed as required.
- Operating experience within the corrective action program relative to program activities was reviewed, including a review of industry operating experience, going back to 2018. It was determined that no changes or enhancements to the program were required.
- The effectiveness review validated the license renewal commitments were properly maintained and there were no changes to the commitments for the aging management program. The license renewal application, the associated NRC safety evaluation report, and the UFSAR description for the Flow-

Accelerated Corrosion program were reviewed to verify that ongoing actions are captured in the FAC AMP program basis document. From this review, it was determined that all license renewal commitments and associated information are contained in the implementing documents and the license renewal commitments are properly annotated.

This operating experience example provides objective evidence of aging management program effectiveness during the first period of extended operation and provides objective evidence that the continued implementation of the program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the subsequent period of extended operation.

2. In 2019, a fleet self-assessment for the FAC/EPC program was conducted. The assessment concluded that the fleet FAC/EPC program is being properly executed across the fleet to provide high quality equipment reliability, ensure reactor safety, and compliance with regulatory requirements. The 12 sites assessed were found to meet the procedural and programmatic requirements established to maintain a successful FAC program. The self-assessment concluded that the NMPNS FAC/EPC program is effectively identifying, mitigating, and proactively addressing component concerns in accordance with programmatic and regulatory guidance.

For NMP1 specifically, the self-assessment identified two deficiencies and three recommendations. The two deficiencies were to update: 1) the program long range inspection and replacement plan and 2) the system susceptibility evaluation. The three recommendations were to: 1) add a piping minimum wall thickness calculation into records management, 2) revise recent outage reports, and 3) perform a verification and validation of the FAC CHECWORKS™ model. These deficiencies and recommendations were entered into the corrective action program and all required actions were completed.

This operating experience example provides objective evidence that NMP1 critically self-assesses program performance and self-identifies actions that support continuous improvement.

3. In March 2023, during a refueling outage, potential issues were identified with weld overlays that were performed on feedwater heaters to mitigate the wear occurring due to FAC. It was noted that the weld overlays did not appear they were executed properly and may pose a risk to the long-term service of the feedwater heater shells. The condition was entered into the corrective action program. It was determined that the welds were acceptable; however, future weld build up work orders would include additional details to document the welds. In addition, an extent of condition was performed on all of the feedwater heaters to determine actions required for other heaters.

This operating experience example provides objective evidence that inspection activities are effectively implemented, extent of condition reviews are performed, and additional actions are taken as required to meet programmatic requirements.

4. In March 2025, during a refueling outage, a 1.5-inch by 2-inch elbow on a feedwater heater vent line was found with a minimum measured wall thickness of 0.086 inch during an inspection, with a minimum allowable thickness being 0.100

inch. The elbow was inspected based on suspected erosion conditions in an upstream orifice. The upstream orifice was replaced with a new orifice assembly. The condition was entered into the corrective action program and additional extent of condition inspections were identified per procedure. All of the extent of condition inspections produced satisfactory results.

This operating experience example provides objective evidence that erosion inspection activities are effectively implemented, extent of condition reviews are performed when inspections do not meet acceptance criteria, and components are replaced as necessary to ensure that aging effects associated with erosion do not impact the intended functions.

5. In 2024, an INPO Questionnaire/Self-Assessment for the FAC/EPC Program was conducted. The assessment reviewed the NMPNS FAC/EPC program to evaluate its conformance to EPRI and Industry guidelines. The following eight functions of the program were evaluated: corporate commitment, analysis, operating experience, inspections, evaluating inspection data, repairing and replacing components, training and engineering judgement, and long-term strategy. There were no gaps or issues reported during this assessment of the NMP1 FAC/EPC Program.

This operating experience example provides objective evidence that NMP1 critically self-assesses program compliance and adherence to regulatory requirements.

The operating experience relative to the Flow-Accelerated Corrosion program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including wall thinning. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Flow-Accelerated Corrosion program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Flow-Accelerated Corrosion program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Flow-Accelerated Corrosion program will provide reasonable assurance that the wall thinning aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.10 Bolting Integrity

Program Description

The Bolting Integrity aging management program is an existing condition monitoring program which manages aging for loss of preload, cracking, and loss of material of safety-related and nonsafety-related closure bolting on pressure-retaining components. The program utilizes recommendations and guidelines delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," TR-1015336, "Nuclear Maintenance Applications Center: Bolted Joint Fundamentals," and TR-1015337, "Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints," for material selection, use of approved lubricants, proper torquing, and leakage evaluations which are implemented during plant surveillance and maintenance activities.

The program activities provide for aging management of closure bolting on pressure-retaining components within the scope of subsequent license renewal. In addition, the program manages aging of submerged mechanical bolting for the traveling screens. The program includes periodic inspection, at least once per refueling cycle, of closure bolting on pressure-retaining components for indication of loss of preload, cracking, and loss of material. The program also credits visual inspection of pressure-retaining bolted joints in ASME Class 1, 2, and 3 systems for leakage and age-related degradation during system pressure tests performed in accordance with ASME Section XI. In addition, the Bolting Integrity aging management program credits volumetric, surface, and visual inspections of ASME Section XI Class 1, 2, and 3 bolts, nuts, washers, and other associated bolting components performed in accordance with ASME Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. The integrity of ASME and non-ASME pressure-retaining bolted joints which contain fluids such as water, oil, or steam is assessed by detection of visible leakage, evidence of past leakage, or other age-related degradation during walkdowns and maintenance activities. Identified degradation conditions are entered into the corrective action program where the condition is evaluated. This could include, when practical, projections of identified corrosion or degradation rates until the next scheduled inspection or replacement. Inspections are performed by personnel qualified in accordance with station procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Direct inspections of non-ASME Code bolting follow station procedures that include inspection parameters for items such as lighting, distance, and offset.

The program also includes preventive measures, such as use of EPRI guidance for the installation, makeup, and material selections of bolted joints; prohibiting the use of lubricants containing molybdenum disulfide; and minimizing the use of high-strength bolting to preclude or minimize loss of preload and cracking.

Aging management reviews have determined that high-strength bolting material with actual yield strength of 150 ksi or greater is not used for closure bolting with bolt diameters greater than 2 inches on pressure-retaining components within the scope of this program. Therefore, sample based volumetric inspection of closure bolting to detect indications of cracking is not applicable.

The program will be enhanced to perform periodic sample inspections of bolting for bolted connections where leakage is difficult to detect. This includes submerged closure bolting on the core spray and containment spray emergency core cooling system suction strainers in a treated water environment, containment spray raw water, diesel generator cooling water, fire, and emergency service water pumps and traveling water screen bolting in a raw water environment, and containment spray pumps in a treated water environment. This also includes closure bolting on systems within the scope of subsequent license renewal which contain air or gas internal environments and systems that are not normally pressurized. Periodic sample inspections will be performed of 20 percent of the bolting in each material and environment combination population up to a maximum of 25 inspections. If the minimum sample size is not achieved during a 10-year period, then alternative inspections may be performed.

For sample-based inspections in which acceptance criteria is not met, the condition will be entered into the corrective action program. The degraded conditions will be evaluated relative to extent of condition against the total population of bolts under similar service conditions, to confirm the timing and extent of subsequent inspections to maintain the components' intended functions throughout the subsequent period of extended operation. Station procedures will be enhanced so that as a minimum, no fewer than two additional inspections will be performed for each inspection that did not meet acceptance criteria, or 10 percent of each applicable material, environment, and aging effect combination, whichever is less. The additional inspections will be completed within the inspection interval for which the original sample-based inspections are conducted. Inspection frequencies may be adjusted based on projected degradation rates.

The following bolting is not managed by in the Bolting Integrity aging management program.

- The bolting components for the reactor vessel closure head are managed by the Reactor Head Closure Stud Bolting (B.2.1.3) program.
- The containment (MC) pressure-retaining bolting is managed as part of the ASME Section XI, Subsection IWE (B.2.1.29) program.
- ASME Class 1, 2, 3, and MC piping and components support bolting, including NSSS component supports, is managed as part of the ASME Section XI, Subsection IWF (B.2.1.30) program.
- Structural bolting, other than ASME Class 1, 2, 3, and MC piping and component supports bolting is managed as part of the Structures Monitoring (B.2.1.33) program, and the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program.
- Crane and hoist bolting is managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13) program.
- Heating and ventilation system bolted joints are managed by the External Surfaces Monitoring of Mechanical Components (B.2.1.23) program.

- Pressure-retaining bolting in a buried environment or underground with restricted access are inspected in conjunction with buried piping and component inspections performed as part of the Buried and Underground Piping and Tanks (B.2.1.27) program.

NUREG-2191 Consistency

The Bolting Integrity aging management program will be consistent with the ten elements of aging management program XI.M18, "Bolting Integrity," specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

1. NUREG-2191 recommends that the scope of the Bolting Integrity program manages aging of closure bolting on pressure-retaining components. The scope of the Bolting Integrity aging management program will also include the aging management of mechanical bolting on the traveling water screens. **Program Element Affected: Scope of Program (Element 1)**

Justification for Exception

Although the submerged mechanical bolts on the traveling water screens are not closure bolting on pressure-retaining components, the Bolting Integrity aging management program will manage the aging effects of loss of preload and loss of material as recommended in NUREG-2191. The component, material, environment, and aging effects for these submerged mechanical bolts are the same as for submerged pressure-retaining closure bolts that are included within the scope of Bolting Integrity aging management program. The alternate means of inspection or testing provided within the Bolting Integrity aging management program for submerged bolting, utilizing sample based visual inspections, has been determined to adequately manage the aging effects of loss of preload and loss of material for these submerged mechanical bolts. A similar exception was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Dresden Nuclear Power Station, Units 2 and 3 (ADAMS Accession No. ML25251A150) and the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos.50-277 and 50-278 (ADAMS Accession No. ML20044D902).

Enhancements

In the elements identified below, the Bolting Integrity program will be enhanced to:

1. Perform periodic visual inspections of a representative sample of bolting for bolted joints where leakage is difficult to detect. A representative sample will consist of 20 percent of the population or up to a maximum of 25 bolts and nuts for each material and environment population, whichever is less, and inspections will be performed during each 10-year period of the subsequent period of extended operation. Inspections will be performed of bolting utilized in joints that are submerged, in systems that are not normally pressurized, and in systems containing air or gas. If the minimum sample size is not achieved during a 10-year period, then alternative inspections may be performed. For submerged

bolting exposed to treated or raw water, alternative inspections may include (1) diver inspections or (2) remote video inspections. For systems not normally pressurized, alternative inspections may include (1) visual inspection during system tests when the system is pressurized or (2) visual inspection for signs of leakage from when the system was under testing. For systems containing air/gas, alternative inspections may include (1) visual inspection for discoloration when leakage from inside the piping system would discolor the external surfaces of the component; (2) monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary; (3) soap bubble testing on the external mating surface of the bolted component; or (4) thermography, when the temperature of the process fluid is higher than ambient conditions around the component. These inspections will verify that no age-related degradation such as cracking, loss of material, or loss of preload are occurring. **Program Elements Affected: Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)**

2. Revise procedures governing the direct visual examination of bolted joints to include inspection parameters such as lighting, distance, and offset. Cameras and video equipment may be used to supplement these inspections. **Program Elements Affected: Detection of Aging Effects (Element 4)**
3. Revise engineering procedures to require results of sampling-based inspections to 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. **Program Elements Affected: Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)**
4. Ensure no fewer than two additional inspections for each sample-based inspection that does not meet acceptance criteria, or 10 percent of the total bolt population of each applicable material, environment, and aging effect combination, whichever is less. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be performed to determine the further extent of inspections. These additional inspections will be completed within the inspection interval in which the original sample-based inspections are conducted. **Program Elements Affected: Corrective Actions (Element 7)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Bolting Integrity program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program (AMP) effectiveness review was performed on the Bolting Integrity aging management program. The AMP effectiveness review assessed the key attributes of effective AMP implementation, including commitment management, detection of aging effects,

corrective actions, and evaluation of industry and site-specific operating experience. The review concluded that inspections have been performed in accordance with specified commitment implementation activities (e.g., recurring preventive maintenance tasks, walkdowns, inspections, etc.). The corrective action program has been utilized to document discrepancies, initiate reviews of component condition and provide timely resolution of noted deficiencies. Review of site and fleet operating experience did not identify any required changes or enhancements to the Bolting Integrity program. The Bolting Integrity aging management program was determined to be effectively managing the aging effects of the components within the scope of the program and identifying degradation prior to failure or loss of intended function.

This operating experience example provides objective evidence that the current Bolting Integrity program is being effectively implemented. Continued implementation and periodic review of this program will effectively manage aging by identifying degradation of the in scope components prior to failure or loss of intended function during the subsequent period of extended operation.

2. During maintenance activities to replace a pump, insulation was removed from the upstream isolation valve where severely degraded bolting was identified for upstream and downstream valve flanges and the body to bonnet bolting. Additionally, the downstream flanges had no insulator kit. The weld crew was able to replace the downstream bolting and install a new gasket and insulator kit as part of the work being performed for replacing and reconfiguring the control room chilled water pump and piping. A work order was generated to replace bolting and gasket for the upstream valve flanges and body to bonnet bolting and is scheduled to be completed during the next available maintenance window in 2027.

This operating experience example provides objective evidence that conditions such as bolting degradation are adequately managed and entered into the corrective action program when degraded conditions are identified.

3. In April 2021, a leak was identified at the control rod drive mechanism flange during the VT-2 hydrostatic test. A work order was generated to retorquing the bolt and the bolt was retorqued to correct the leakage.

This operating experience example provides objective evidence that ASME Code VT-2 inspections of pressure-retaining components are capable of monitoring leakage and are adequately managed and entered into the corrective action program when degraded conditions are identified.

The operating experience relative to the Bolting Integrity program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material, cracking, and loss of preload. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Bolting Integrity program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Bolting Integrity program will

effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Bolting Integrity program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.11 Open-Cycle Cooling Water System

Program Description

The Open-Cycle Cooling Water System aging management program is an existing preventive, mitigative, condition monitoring and performance monitoring program based on the implementation of NRC Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and includes nonsafety-related portions of the open cycle cooling water system. The program includes: (a) surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of heat exchangers, and (c) periodic inspection and maintenance so that corrosion, erosion, cracking, fouling, and biofouling that results in the reduction of heat transfer cannot degrade the performance of systems serviced by the open cycle cooling water systems. The program also includes evaluation, repair, or replacement of components that do not meet minimum wall thickness requirements. The program applies to components constructed of steel, cast iron, stainless steel, concrete, copper alloys and polyvinyl chloride (PVC). This program includes guidance beyond the requirements contained in NRC GL 89-13, such as inputs from industry reports and documents (e.g., EPRI documents) that address operating experience such that aging effects are adequately managed.

The program manages piping, piping components, and heat exchanger components in safety-related and nonsafety-related raw water systems that are exposed to a raw water environment for loss of material, cracking, hardening or loss of strength, reduction of heat transfer, and flow blockage. The guidelines of NRC GL 89-13 are implemented through the station GL 89-13 activities for heat exchangers and the raw water corrosion program for piping and piping components. System and component testing, flushing, visual inspections, non-destructive examination, and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained.

The program includes those plant systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in NRC GL 89-13. 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 station commitments to NRC GL 89-13 to verify heat transfer capabilities. Test results and the results of visual inspections that do not meet acceptance criteria are evaluated in accordance with the corrective action program. For heat exchangers that are tested for heat transfer capability, test results are trended to verify adequacy of testing frequencies. For heat exchangers that are inspected for degradation in lieu of testing, inspection results are trended to evaluate adequacy of inspection frequencies.

Piping is non-destructively examined to ensure that there is no loss of material which could result in loss of intended function. Examinations that do not meet acceptance criteria are evaluated in accordance with the corrective action program. For ongoing degradation due to specific aging mechanisms (e.g., microbiologically influenced corrosion), the program includes trending of wall thickness measurements at susceptible locations to adjust the monitoring frequency and the number of inspection locations.

Inspections and tests are performed by personnel qualified in accordance with station procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow station procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The program does not manage loss of coating integrity for internal coatings or linings. The program only manages carbon steel (with internal coatings) for the aging effect of flow blockage. Loss of coating integrity in raw water systems is managed by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28) program.

Aging effects associated with nonsafety-related service water systems not included within the scope of NRC GL 89-13 (e.g., portions of the service water system and circulating water system) are managed by this program.

Aging of water-based fire suppression systems, other than recurring internal corrosion, are managed by the Fire Water System (B.2.1.16) program.

The Open-Cycle Cooling Water system aging management program does not manage loss of material or loss of preload in submerged bolting. These aging effects are managed by the Bolting Integrity (B.2.1.10) program.

NUREG-2191 Consistency

The Open-Cycle Cooling Water System aging management program will be consistent with the ten elements of aging management program XI.M20, "Open-Cycle Cooling Water System," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Open-Cycle Cooling Water System program will be enhanced to:

1. Perform a minimum of 10 inspections for recurring internal corrosion in the raw water systems, including water-based fire systems, every 24 months until the rate of recurring internal corrosion occurrence no longer meets the criteria for recurring internal corrosion as defined in SLRA Section 3.3.2.2.7. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted as appropriate. Evaluation of the inspection results will include: (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of re-inspection interval.
Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Corrective Actions (Element 7)

2. Revise the raw water piping inspection program to require that any internal visual inspections performed on in scope concrete piping for subsequent license renewal, parameters monitored or inspected, acceptance criteria and qualifications of inspectors be in accordance with ACI 349.3R and ACI 201.R1. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6)**
3. Perform cleaning, flushing, and inspections on the cooling coils for two of the reactor building area coolers and two of the turbine building area coolers during each 10-year period. Coils are to be internally cleaned, flushed, then inspected. Inspection method to be capable of detecting wall thinning or loss of material on the internal raw water side of the tubes. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**
4. Perform quarterly monitoring of the service water and containment spray raw water pump motor bearing temperatures. The results will be trended to establish a baseline, and indications of abnormal temperature trends will be investigated in accordance with the corrective action program. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**
5. Perform cleaning, flushing and inspection of the service water and containment spray raw water pump motor cooling tubes during maintenance on the motors on a frequency not to exceed 10 years. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Open-Cycle Cooling Water System aging management program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed on the Open Cycle Cooling Water System aging management program. The effectiveness review concluded that the program is effectively managing aging effects of in scope SSCs to ensure loss of intended function does not occur. The results of the effectiveness review elements were as follows:
 - Review of the NMP1 Open Cycle Cooling Water System aging management program documentation confirmed that detection of aging effects was timely and implementing activities were effective in managing and resolving issues prior to loss of function. Results of preventive maintenance (PM) procedure reviews, issue report reviews, and interviews with system managers indicate that the AMP requirements are being met. There were some minor gaps noted regarding documentation.

- Corrective action program issue reports were reviewed to verify that appropriate corrective actions were taken in a timely manner; unexpected conditions identified; and corrective actions developed as necessary. No new degradation mechanisms were identified and no changes to the AMP were required.
- Operating experience reviews were performed routinely. No issues were identified that required any additional program changes. No gaps applicable to the Open Cycle Cooling Water System aging management program were identified.
- A review of program commitments was performed to verify that the commitments or requirements are properly documented and maintained. All the AMP implementing documents are listed in the Program Basis Document and were reviewed for proper annotations. No deficiencies were identified from this review.

This operating experience example provides objective evidence of aging management program effectiveness during the first period of extended operation and that the continued implementation of the program will effectively manage aging during the subsequent period of extended operation.

2. In December 2021, one of the reactor building closed loop cooling system (RBCLC) heat exchangers was cleaned and inspected under a routine heat exchanger preventive maintenance work order. The as-found conditions identified about 30 pounds of zebra mussels and 20 pounds of mud/silt material. The zebra mussels and material were removed, the heat exchanger was cleaned, and the condition was entered into the corrective action program to document the findings and for trending purposes.

This operating experience example provides objective evidence that testing and inspection activities implemented by the program are capable of detecting evidence of flow blockage due to macro-biological fouling and silt accumulation prior to loss of intended function. This example also demonstrates that the corrective action program is effectively used to document material conditions of heat exchangers when indications of macro-biological fouling and silt buildup are identified.

3. In April 2025, it was identified that test data obtained while performing a heat removal capacity test on a containment spray heat exchanger was not representative of the heat exchanger performance capability and a new data set should be collected. Data obtained from field conditions is extrapolated to design conditions to determine the heat removal capacity. The readings on the resistance temperature detectors (RTDs) were inconsistent with expectations and it was discovered that the RTDs were not insulated in accordance with the procedure. This resulted in abnormal temperature readings. It was determined that the test would be reperformed prior to reaching the PM due date. The PM has a due date in December 2026.

This operating experience example provides objective evidence that the results of testing activities implemented by the program are evaluated and trended to

identify degrading performance. This example also demonstrates that the corrective action program is effectively used to identify abnormal conditions and ensure that appropriate corrective actions are taken to ensure the equipment is meeting the intended function.

4. In May 2025, eddy current testing was performed on a heat exchanger tube bundle in the turbine building closed loop cooling system. Inspection results required 58 tubes to be plugged which represents 5.9 percent of the 986 total tubes and was within the engineering allowance for operability. The majority of the defects were attributed to outside diameter wear at support structures; however, some of the tube defects were attributed to inside diameter pitting. The results of the inspection and tube plugging were discussed with the system engineer then documented in the corrective action program for trending purposes.

This operating experience example provides objective evidence that the existing aging management program utilizes appropriate techniques to inform the program and identify locations for tube plugging. This example also demonstrates that inspection results are evaluated and documented in the corrective action program.

5. In March 2017, an ultrasonic thickness examination was performed on a component in the service water system. The component was a 24-inch elbow with a low reading of 0.312 inches compared to a design minimum wall of 0.328 inches. A new minimum wall thickness was calculated and the continued service life of the component was determined. The examination of this component was a repeat inspection done to monitor wear in this large bore service water line. The overall wear on this component was relatively low, given the time in service. No additional actions were required.

This operating experience example provides objective evidence that the corrective action program is effectively used to assess conditions not meeting acceptance criteria for inspected components and to identify required follow-up actions. This example also demonstrates that repeat examinations are performed in raw water systems to monitor corrosion rates and determine the remaining service life of components and to ensure future reliable system operation.

6. A review of NMP1 operating experience over a 10-year period has revealed recurring internal corrosion (RIC) in steel piping exposed to raw water from Lake Ontario. The program identifies inspection locations based on the risk associated with specific pipe locations. The risk is determined by the combination of piping corrosion susceptibility (based on material, piping size, piping configuration, flow velocity, and past inspection data) and the consequences of pipe leaks/ruptures or other integrity issues (e.g., piping below minimum required thickness). The selection of inspection locations using risk insights based on susceptibility to aging effects and consequences of failure is an acceptable approach to address RIC as discussed in SLRA Section 3.3.2.2.7. To ensure sufficient inspections are performed to monitor RIC in steel piping exposed to raw water, the NMP1 Open-Cycle Cooling Water System program will be enhanced as shown above to require a minimum of 10 wall thickness

measurements every 24 months until the rate of recurring internal corrosion occurrence no longer meets the criteria for recurring internal corrosion as defined in Section 3.3.2.2.7 of NUREG-2192.

This operating experience example provides objective evidence that plant operating experience is reviewed for recurring internal corrosion, and appropriate actions are included in aging management programs.

The operating experience relative to the Open-Cycle Cooling Water System aging management program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, flow blockage, loss of material, and reduction of heat transfer. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Open-Cycle Cooling Water System aging management program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Open-Cycle Cooling Water System aging management program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Open-Cycle Cooling Water System program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.12 Closed Treated Water Systems

Program Description

The Closed Treated Water Systems aging management program is an existing mitigative program which includes condition monitoring activities that manage loss of material, cracking, and reduction of heat transfer in piping, piping components, pump casings, strainers, hoses, valve bodies, tanks, and heat exchanger components exposed to a closed cycle cooling water environment. The Closed Treated Water Systems program includes (1) nitrite-based and pure water based treatment, including pH control and the use of corrosion inhibitors to modify the chemical composition of the water such that the function of the components are maintained and the effects of corrosion are minimized; (2) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (3) inspections to determine the presence or extent of degradation.

The Closed Treated Water Systems program activities are implemented through station procedures. The performance of sample analyses ensures water chemistry parameters are maintained within the goal ranges specified by procedures based on EPRI closed cooling water chemistry guidelines. The NMP1 Closed Treated Water Systems aging management program specifies the use of EPRI 3002000590, "Closed Cooling Water Chemistry Guideline," Revision 2, December 2013. Monitoring of water chemistry parameters also ensures contaminants are kept below applicable limits to prevent or limit corrosion. Testing and treating for microbiological growth are performed. Condition monitoring activities will include periodic inspections using techniques capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects as described below.

Periodic inspections for indication of loss of material, cracking, and fouling of a representative sample are performed, at a minimum, in each 10-year period during the subsequent period of extended operation. The inspections will include periodic inspections to satisfy sample size requirements using techniques capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects.

The representative sample of inspections are performed for each material, aging effect, and water treatment program combination and focus on the components most susceptible to aging because of time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water. A technical justification of the methodology used for determining sample size and for selecting components for inspection will be included in the program documentation. Although Nine Mile Point Nuclear Station is a multi-unit site, inspection activities under this program apply only to a single unit (Unit 1). Water chemistry programs monitor various chemistry parameters and require out-of-specification conditions to be corrected under the corrective action program.

Heat transfer capability of heat exchanger surfaces are evaluated by either visual inspections to determine surface cleanliness or functional testing to verify that design heat removal rates are maintained.

Identified age-related degradation is projected until the next scheduled inspection and results are evaluated to confirm that the sampling bases will maintain the component's intended functions throughout the subsequent period of extended operation. If fouling is identified, then the overall effect will be evaluated for reduction of heat transfer, flow blockage, and loss of material.

Additional inspections will be conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections will be determined in accordance with the corrective action program; however, no fewer than two additional inspections for each inspection that did not meet acceptance criteria, or 10 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

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 procedures consistent with the ASME Code. Non-ASME Code inspections will follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The Closed Treated Water Systems program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are generally applicable to all Constellation plants, with certain aspects limited to operation beyond 60 years. The equivalent Closed Treated Water Systems program for Peach Bottom Atomic Power Station, including the aspects of the program applicable to operation beyond 60 years, has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Closed Treated Water Systems program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Closed Treated Water Systems aging management program will be consistent with the ten elements of aging management program XI.M21, "(XI.M21A) Closed Treated Water Systems", specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Closed Treated Water Systems program will be enhanced to:

1. Perform condition monitoring including sample-based periodic inspections using techniques (visual, surface, or volumetric) capable of detecting loss of material, cracking, and fouling, as appropriate to verify the effectiveness of water chemistry control to mitigate aging effects in each 10-year period during the subsequent period of extended operation. If degradation is identified, then the rate of degradation will be projected until the next scheduled inspection. Additional sample-based inspections will be performed if unacceptable aging is identified. If those inspections identify unacceptable aging, then the corrective action program will be used to determine the extent of condition and extent of cause to determine the extent of further inspections. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), Corrective Actions (Element 7).**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Closed Treated Water Systems program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed to verify that the existing Closed-Cycle Cooling Water Systems aging management program described in UFSAR Section C.1.13 is being effectively implemented in the first license renewal period of extended operation. The program manages loss of material and reduction of heat transfer in components exposed to closed cooling water with preventive measures to minimize corrosion by maintaining chemistry parameters and by performing non-chemistry monitoring. The non-chemistry monitoring consists of inspection and nondestructive examinations (NDE) of selected in scope heat exchangers exposed to closed-cycle cooling water environments. Operating experience applicable to the program was evaluated. The evaluation concluded that closed cooling water chemistry was maintained within closed cooling water guidelines and there were no indications of loss of system function, excessive degradation, or potential aging issues of closed cooling water components due to exposure to the closed cooling water environment. The activities to monitor and control closed cooling water chemistry has resulted in the effective implementation of this aging management program. One improvement identified was to ensure accuracy in license renewal commitment markup of procedures. Relevant procedures requiring updates were identified and the action has been created to perform this task.

This operating experience provides objective evidence of aging management program effectiveness during the first period of extended operation and demonstrates that the continued implementation of the Closed Treated Water

Systems aging management program will effectively manage aging such that intended functions will be maintained through the subsequent period of extended operation. In addition, this example demonstrates that program effectiveness reviews are performed to drive continuous improvement of the program.

2. One of the control room HVAC chillers was replaced in March 2014. After this replacement, action levels were exceeded for chloride, sulfate, and conductivity on several occasions. The initial action taken to correct the control room HVAC water chemistry was to “feed and bleed” the system. Reactor building closed loop cooling system (RBCLC) water was added and the control room HVAC water which exceeded action levels was removed to restore chemistry parameters within normal limits. Following the initial corrective action, NMP1 implemented a robust solution through a plant modification which installed a side stream demineralizer directly on the control room HVAC system, in addition to the existing side stream demineralizer on the RBCLC. This modification reduced the action level issues and enabled the control room HVAC pure water system to consistently maintain water chemistry within normal limits.

This operating experience provides objective evidence that the station identifies adverse trends, enters them into the corrective action program, and appropriate actions are taken in a timely manner to resolve the trends.

3. LaSalle County Nuclear Station discovered a leak from a small crack at the base of the emergency diesel generator (EDG) jacket water outlet piping transition piece in September 2020. This part had been in service for the entire life of the plant and failed due to cyclic fatigue. Nine Mile Point Nuclear Station, Unit 1 identified no leaks on the similar part of their jacket water cooling piping but proactively created a work order to replace the transition piece at the next maintenance window. This component was replaced on both EDGs in 2022.

This operating experience provides objective evidence that issues potentially common across the fleet are communicated across the fleet in an effective manner and promptly acted upon by the station to ensure they are entered into the corrective action program.

4. Ultrasonic Thickness testing (UT) inspections for the closed treated water system components were prescribed during first license renewal. The locations were selected, inside and outside of the drywell, to monitor for loss of material due to corrosion based on the expected aging mechanisms. Locations inside of the drywell were also selected based on the appearance of the outside of the piping and locations of highest stress. In November 2016, UT readings were taken on a drywell air cooler return header elbow. The results of the inspection were acceptable and documented under the work order as well as the inspection report. Ultrasonic testing is performed on a recurring basis to monitor for trends.

This operating experience provides objective evidence that aging management inspections are performed and documented in accordance with program planning in order to manage the aging of components.

The operating experience relative to the Closed Treated Water Systems program did not identify an adverse trend in performance. Mitigative program activities include chemistry controls which ensure system chemistry parameters are maintained within

established limits. Condition monitoring inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material, cracking, fouling and reduction of heat transfer. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Closed Treated Water Systems program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Closed Treated Water Systems program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Closed Treated Water Systems program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.13 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 aging management program is an existing condition monitoring program that manages the aging effects of loss of material due to corrosion and wear, cracking, deformation, and indications of loss of preload for steel and stainless steel load handling bridges, structural members, structural components and bolted connections for cranes, hoists, trollies, and monorail beams exposed to an air-indoor, uncontrolled environment. Procedures and controls implement the guidance on the control of overhead heavy load cranes specified in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" and ASME B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top running Trolley Hoist)." The program utilizes periodic visual inspections as described in the ASME B30 series of standards for inspection, detection of aging effects, evaluation, and repair of aging degradation. Monitoring and maintenance of structural components of crane handling systems comply with the maintenance rule requirements provided in 10 CFR 50.65.

The scope of the aging management program is compliant with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." Overhead lifting equipment that operates over safety-related equipment is included within the scope of license renewal. Cranes and hoists, including the reactor building overhead cranes, turbine building overhead cranes, numerous equipment handling cranes, hoists, trollies, and monorails are managed by the program. Also, within the scope of the program are handling systems that lift 'light' loads including equipment, tools, and fuel, over fuel and safety-related equipment within the spent fuel pool and reactor cavity.

Inspection frequency and scope is in accordance with the recommendations for periodic inspection within the ASME B30 series of standards. Periodic inspections are performed annually for frequently operated handling systems. For handling systems that are infrequently in service, such as those only used during refueling outages or for specific maintenance activity, periodic inspections are performed just prior to use. Aging effects that are identified by inspections are entered into the corrective action program for evaluation and repair.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program utilizes periodic inspections that effectively detect degradation before loss of intended function. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation.

The program will provide reasonable assurance that the aging effects addressed by this aging management program will be adequately managed during the subsequent period of extended operation.

NUREG-2191 Consistency

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be consistent with the ten

elements of aging management program XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be enhanced to:

1. Provide additional procedural guidance to include inspection of bolting for cracking and loss of material. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

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 will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed of the cranes, hoists, trollies, and refueling handling systems covered by the Inspection of Overhead Heavy Load and Light Load Handling Systems Program. The existing program requires periodic visual inspections of in scope handling systems, performed in accordance with the guidance provided within the ASME B30 series of standards. The purpose of the review was to verify the adherence of the existing crane inspection activities program, which is to inspect, identify, and correct age-related degradation of in scope handling systems, is being effectively implemented during the first license renewal period of extended operation.

The aging management program effectiveness review included a review of maintenance history for documented completion of periodic inspections from 2018 through 2025, and a review of operating experience within the corrective action program for identified age-related degradation of in scope handling systems during the same period. The review identified that historical data indicates that preventive maintenance has been adequate and that degradation, if identified, is corrected prior to loss of intended function.

The inspections performed in accordance with the crane inspection activities program have identified very few age-related deficiencies associated with passive structural and bolting components; and those identified have been minor in significance with evaluations that concluded that the structural integrity of the crane/hoist structure was not affected. This is as expected since almost all the

handling systems within the scope of the program are infrequently used and are in an air-indoor, uncontrolled environment. These periodic inspections, along with the evaluation of deficiencies within the corrective action program, have resulted in the effective implementation of this aging management program. One improvement identified was to ensure accuracy in license renewal commitment markups of procedures. Relevant procedures requiring updates were identified and the action has been created to perform this task.

The aging management program effectiveness review determined that the program is being implemented in accordance with crane inspection activities program.

2. In 2023, a preventive maintenance inspection was conducted on the 150-ton reactor building overhead crane. No aging effects were identified during the inspection. The only degradation that was identified was a broken safety latch spring on the auxiliary hook. The issue was entered into the corrective action program. A work request was initiated, and the safety latch was replaced.

This example demonstrates that age-related degradation is effectively managed by the program and conditions such as a degraded safety latch are identified and corrected.

The operating experience relative to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program will provide reasonable assurance that the loss of material and loss of preload aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.14 Compressed Air Monitoring

Program Description

The Compressed Air Monitoring aging management program is an existing condition monitoring program that consists of monitoring moisture content and corrosion, and performance of the compressed air system, including (a) preventive monitoring of water (moisture), and other contaminants to keep within the specified limits and (b) inspection of components for indications of loss of material due to corrosion. The program manages loss of material in carbon steel, stainless steel, copper alloy piping, piping components, valve bodies, accumulators, and tanks in a dry air environment.

This program is based on the NMP1 response to NRC Generic Letter (GL) 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," and INPO's SOER 88-01, "Instrument Air System Failures." It also relies on the guidance from the ASME operations and maintenance standards and guides ASME OM-SG-1998, Part 17, "Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants," ANSI/ISA-S7.3-1975, "Quality Standard for Instrument Air," and EPRI TR-108147, "Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079," for testing and monitoring air quality and moisture.

Program activities include periodic air quality checks at various locations to ensure the dew point, particulates, and hydrocarbons are maintained within specified limits. Air quality test data is analyzed against established acceptance criteria. Trending is performed to ensure aging effects are identified and corrective actions are taken in a timely manner.

Inspections of the internal surfaces of accessible compressed air system components for signs of loss of material due to corrosion are performed. This inspection activity provides additional assurance that the systems within the scope of license renewal will perform their intended function.

Results from inspections are compared with established acceptance criteria to provide for timely detection of aging effects. The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to 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. The corrective action program ensures that the conditions adverse to quality are promptly corrected. The station corrective action program is implemented in accordance with the requirements of the 10 CFR Part 50, Appendix B quality assurance program.

NUREG-2191 Consistency

The Compressed Air Monitoring aging management program will be consistent with the ten elements of aging management program XI.M24, "Compressed Air Monitoring," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Compressed Air Monitoring aging management program will be enhanced to:

1. Revise program implementation and criteria to be in accordance with ANSI/ISA-7.0.01-1996 guidelines. The existing program is based on ANSI/ISA-7.3.1975 guidelines and the enhancement will bring the existing program in line with current standards and vendor recommendations without any impact on the programs ability to maintain component intended functions during the subsequent period of extended operation. **Program Elements Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6)**
2. Revise program implementation and criteria to be in accordance with ASME OM-2012 Division 2, Part 28 guidelines. The existing program is based on ASME OM-1998, Part 17 guidelines and the enhancement will bring the existing program in line with current standards and vendor recommendations without any impact on the programs ability to maintain component intended functions during the subsequent period of extended operation. **Program Elements Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Compressed Air Monitoring aging management program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation:

1. In 2025, a Compressed Air Monitoring AMP effectiveness review was performed. The effectiveness review verified that implementing activities, including air quality test, were being performed at the scheduled periodicity as specified in the first license renewal commitment. In addition, issues entered into the corrective action program, and associated corrective actions were reviewed. Corrective actions were found to be timely and effective in addressing conditions adverse to quality. Recommendations from NUREG-1801 revisions were considered; changes for stainless-steel components were incorporated, but no further changes were needed. Finally, industry and station operating experience was reviewed to determine if it was being used to inform the Compressed Air Monitoring program. No aging management program changes were deemed necessary based on the review.

This operating experience example provides objective evidence that the Compressed Air Monitoring program is effectively managing aging effects for in-scope SSCs, preventing loss of intended function. All tasks are completed at or above required frequencies, corrective actions are timely and adequate, and no

new degradation mechanisms were identified. No issue reports were generated as a result of this review. The Compressed Air Monitoring aging management program will continue to be effective in managing loss of material for compressed air system piping and components, ensuring reliable long-term operation of the compressed air systems within the scope of this program.

2. In 2021, a leak was identified from a drain valve packing for instrument air. The valve packing could not be tightened due to corrosion. The leak was deemed to be minor, and the drain valve functional though degraded. The packing was adjusted to stop the leaking. The degraded conditions were evaluated in the corrective action program with no additional inspections conducted and no adverse trends that would warrant a change in inspection frequency or need to initiate additional preventive maintenance.

This operating experience example provides objective evidence that conditions such as leakage are adequately managed and entered into the corrective action program when degraded conditions are identified.

3. In 2024, during blowdowns, operators identified condensation leakage from the valve packing for the instrument air compressor (IAC). A leak from the valve packing could cause the IAC to cycle on and off more frequently. An investigation determined the leakage was minor and within the capacity of the instrument air system. The valve remained functional, and a catch basin was installed via a work order. The degraded conditions were evaluated in the corrective action program with no additional inspections conducted and no adverse trends that would warrant a change in inspection frequency or need to initiate additional preventive maintenance.

This operating experience example provides objective evidence that conditions such as leakage are adequately managed and entered into the corrective action program when degraded conditions are identified.

The operating experience relative to the Compressed Air Monitoring aging management program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including corrosion and oil leaks. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Compressed Air Monitoring aging management program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Compressed Air Monitoring aging management program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Compressed Air Monitoring program will provide reasonable assurance that the loss of material aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are

maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.15 Fire Protection**Program Description**

The Fire Protection aging management program is an existing condition monitoring program that manages the identified aging effects for the fire barriers, halon suppression system, low-pressure carbon dioxide systems, and associated components in air-indoor uncontrolled, air-outdoor, and condensation environments using periodic inspections and functional testing to detect aging effects prior to loss of intended functions. System functional tests and visual inspections are performed in accordance with guidance from National Fire Protection Association Codes and Standards. The program applies to piping, piping components, spill retaining curbs, tanks, and fire barriers (doors, dampers, penetration seals, walls, floors, wraps, and ceilings). Fire protection component materials consist of carbon steel, galvanized steel, copper alloy, reinforced concrete, concrete block, cementitious and silicate fireproofing, elastomers, polymers, and stainless steel.

The Fire Protection program monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent loss of intended functions. The program utilizes periodic visual inspections of fire barrier penetration seals and wraps for signs of degradation such as loss of material, cracking/shrinking, wear, seal separation from walls and components, and separation of layers of material to manage fire barrier aging. The program specifies visual examinations of the fire barrier walls, ceilings, and floors in structures within the scope of license renewal for signs of degradation such as loss of material and cracking/spalling. Periodic visual inspections and functional tests are used to manage the aging effects of fire doors and fire damper assemblies. Inspection and testing frequencies are consistent with the approved Fire Protection program. These inspections and tests are implemented through station procedures and recurring task work orders. Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the corrective action program for proper disposition.

The program also uses functional testing and periodic external surface visual inspections for signs of degradation, such as loss of material, to manage aging of the low-pressure carbon dioxide and halon fire suppression systems in scope of license renewal.

NUREG-2191 Consistency

The Fire Protection aging management program will be consistent with the ten elements of aging management program XI.M26, "Fire Protection," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Fire Protection aging management program will be enhanced to:

1. Perform visual inspections of combustible liquid spill retaining curbs. Combustible liquid spill retaining curbs will be inspected for signs of age-related degradation that could affect the intended function of the component. Curbs will be inspected for signs of cracking, spalling, corrosion, or loss of material that could impede the leak tight functionality of the curb. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**
2. Perform visual inspections of fire doors for age-related degradation. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**
3. Visually inspect stainless steel fire damper housings for cracking. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**
4. Perform an inspection of not less than 10 percent of each type of seal during each inspection interval. **Program Elements Affected: Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Fire Protection program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In September 2025, an effectiveness review of the Fire Protection aging management program was performed per procedural requirements. The detection of aging effects review objective concluded: “The comprehensive review of completed preventive maintenance has resulted in no indication of SSCs under the Fire Program aging management program to have sustained a loss of their intended function. Where degraded conditions were identified, the condition was identified in an issue report and the action to correct the condition was performed under a work order.” The corrective actions review concluded: “No changes to the Fire Program aging management program were noted from the review.” The operating experience review concluded: “No enhancements for the Fire Program aging management program were noted from the OE review.” One age-related OE is discussed in the effectiveness review relating to a break in fire main piping. However, this OE is not relevant to the Fire Protection aging management program and is specifically addressed in the Fire Water System (B.2.1.16) program. Therefore, it is not addressed here.

The effectiveness review provides objective evidence that the Fire Protection program is effective and, if required, reviews are in place to inform or enhance the program when necessary. This is done through the periodic internal review of program implementation. There is confidence that implementation of the Fire

Protection program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

2. In March 2023, an issue report (IR) was entered into the corrective action program to document lessons learned and enhancements to be made to the fire barrier/penetration sealing inspection program. The IR documents the need to clarify the work description and to create individual tasks for each element of the procedure to be performed. In addition, the IR documents the need for improved place keeping and organization in the datasheets. The IR recommends tabulating the penetrations in the work plan in the order that they would be identified, physically, in the station. As a result, the job plan for the Unit 1 outage was revised and the lessons learned were applied to the job plan for the upcoming Unit 2 outage.

This operating experience example demonstrates that periodic assessments of the Fire Protection Program are performed to identify the areas that need improvement to maintain the quality performance of the program and that the program is informed and enhanced, when necessary. This operating experience also shows that lessons learned are shared between operating units.

3. In April 2021, while performing fire barrier penetration seal inspections, a penetration seal was identified as degraded. On one side of the fire barrier, the sealant was no longer enveloping the penetration. The sealant on the other side of the fire barrier was intact. The observation of the degraded condition was immediately entered into the corrective action program for evaluation which determined that the penetration seal required repair. A work order to perform the repair was created and the penetration seal was repaired in accordance with station procedures within the month.

This operating experience example demonstrates that the inspection elements of the Fire Protection aging management program effectively identify degraded conditions and correct them prior to loss of intended function.

The operating experience relative to the Fire Protection program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, blistering, loss of material, separation, hardening, loss of strength and shrinkage, and change in material properties. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Fire Protection program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Fire Protection program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Fire Protection program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.16 Fire Water System

Program Description

The Fire Water System aging management program is an existing condition monitoring, performance monitoring, and preventive program that manages the loss of material in raw water, air – indoor, air – outdoor, and condensation environments for water-based fire protection systems due to corrosion, including microbiologically influenced corrosion (MIC), cracking, and flow blockage due to fouling. The program manages these aging effects by monitoring system pressure, flushing the system fire header, flow testing the buried system fire header, performance testing the fire pumps, full flow flushing and flow verification the fire hydrants, flushing and flow testing sprinkler and deluge systems, and visually inspecting systems using the guidance of NFPA 25, 2011 Edition. The water-based fire protection systems consist of sprinklers, nozzles, fittings, valve bodies, fire pump casings, tanks (retard chambers), hydrants, hose stations, standpipes, strainers, and aboveground and buried piping and components.

These components are tested in accordance with the applicable NFPA codes and standards as recommended by NUREG-2191, Revision 1, with deviations as described in the NRC-approved Fire Protection Program. Flow testing, visual inspections, and volumetric wall thickness examinations are performed to ensure that loss of material, cracking, and flow blockage are adequately managed. By review of plant-specific operating experience, recurring internal corrosion is an existing condition. Recurring internal corrosion (RIC) is addressed by the Open Cycle Cooling Water System (B.2.1.11) aging management program and is not managed by this program.

Inspections and tests follow station procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes for an adequate examination.

The water-based fire protection system is normally maintained above the auto start setpoint of the motor-operated fire pump and monitored such the start of the fire pump due to loss of system pressure is immediately detected in the main control room and corrective actions initiated. Further loss of system pressure would be alarmed in the control room by the auto start of the diesel fire pump. An unexpected start of a fire pump requires operator response and investigation to determine the cause.

The Fire Water System program includes replacement or testing of a representative sample of sprinklers after they reach 50 years, 60 years, 70 years, and 80 years of service if a plant-specific evaluation cannot determine the water is non-corrosive to sprinklers.

External surfaces of buried fire main piping are evaluated as described in the Buried and Underground Piping and Tanks (B.2.1.27) aging management program.

NUREG-2191 Consistency

The Fire Water System aging management program will be consistent with the ten elements of aging management program XI.M27, "Fire Water System," specified in NUREG-2191 with the following exceptions:

Exceptions to NUREG-2191

1. NUREG-2191, AMP XI.M27, Table XI.M27-1 recommends compliance with the requirements of NFPA 25, Section 6.3.1 performed at a frequency of five years. NFPA 25, Section 6.3.1 requires a flow test at the hydraulically most remote hose connection.

Nine Mile Point Nuclear Station, Unit 1 does not perform a flow test at the hydraulically most remote hose connection. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Corrective Actions (Element 7).**

Justification for Exception

A flow test at the hydraulically most remote hose connection is not required for an effective Fire Water System program at NMP1 because the current program performs alternative tests that meet the intent of the section more frequently than what is required by NFPA 25, Section 6.3.1.

The intent of the flow test at the hydraulically most remote hose connection is to verify the capability of the fire water system to provide the required pressure at the required flow at the most remote point in a hose station zone. This verifies the lack of flow blockage within the standpipe. At NMP1, the intent of this test is accomplished by the performance of other tests and assurance is provided by the use of a comprehensive corrective action program (CAP). To ensure the fire water system is capable of providing the required pressure at the required flow rate to the base of each standpipe, the station performs annual fire protection loop flow tests. In addition, NMP1 performs flow tests and flushes of the lowest standpipe point in each building every five years. The flow testing is capable of identifying a degraded water supply and the flushing removes fouling from system piping which would settle at the lowest point. Abnormal indications are entered into CAP for inspection and resolution, as necessary. Combined, these tests ensure adequate flow is provided to the base of each standpipe. To ensure this flow remains available at each hose station, an additional flow test is not required. The standpipe material and environment are the same as the interior piping that is tested during the low point flow and flushes. Therefore, if no age-related degradation is detected in the low point flow test, an operability test to verify there is no flow blockage is sufficient to verify flow would be available at the most remote point. The NFPA 25 requirement considers sources of flow blockage other than age-related degradation including sources that could originate from outside of the owner controlled fire supply in non-nuclear station applications. The NMP1 fire water system is controlled from the suction source of the fire pumps to the discharge points. Aging management of various material and environment combinations is performed via a multitude of tests and inspections and CAP is credited to ensure adequate extent of condition evaluations are performed when required. In addition, the NMP1 workforce is

trained and managed to limit the potential of foreign material entering a system and becoming a non-age-related source of flow blockage. Flow blockage verification tests are performed by the current NMP1 Fire Protection Program in the form of hose station operability tests. The hose stations are broken into two groups. One group for non-high radiation hose stations and one group for high radiation hose stations. The operability test for the non-high radiation hose stations group is performed annually. The high radiation hose station group is performed every two years. The operability test tests each hose station on every standpipe to ensure there is water flow and is performed more frequently than the five-year requirement. These operability tests are performed on 99 hose stations in non-high rad areas and 12 hose stations in high radiation areas.

The alternative testing described above are capable of meeting the intent of NFPA 25, Section 6.3.1 requirements and are performed at frequencies that exceed the requirement. The station ensures that the fire water system is capable of providing the required flow at the required pressure at the base of the standpipes, ensures that standpipes are not blocked, and flushes the lowest point in each building to remove fouling. Finally, the station CAP process ensures abnormal conditions, when identified, are evaluated and corrected as required. Therefore, a flow test at the hydraulically most remote hose connection is not required for an effective Fire Water System aging management program at NMP1.

2. NUREG-2191, AMP XI.M27, Table XI.M27-1 recommends compliance with the requirements of NFPA 25, Section 7.2.2.3 performed annually and after each significant flow. NFPA 25, Section 7.2.2.3 requires the station perform private service main mainline strainer inspections.

Nine Mile Point Nuclear Station, Unit 1 does not perform annual or post significant flow mainline strainer inspections of the private service main fire pump discharge strainers. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4).**

Justification for Exception

The NMP1 Fire Protection Program is a risk-informed performance based program that is licensed in accordance with the requirements of NFPA 805. Annual and post significant flow inspections of the mainline strainers are not required for an effective Fire Water System aging management program due to operating experience, the periodic performance of other tests and inspections, and the configuration of the strainers.

An annual inspection of the mainline strainers was historically performed at NMP1. However, the station retired the inspection in 2014. Between the years of 2009 and 2014, the station performed seven annual inspections of the stainless steel mainline strainers. These inspections resulted in the identification of a positive trend in results indicating no failures (e.g., no fouling and no loss of material) and lack of need for the inspection. The basis for retiring the inspection, which also addresses the strainer configuration, was as follows:

The strainers are duplex strainers with the strainer remaining aligned to one basket all year long. Issues would be seen during the monthly surveillance run which records the strainer [differential pressure]. Opening and cleaning the strainer every year under preventive maintenance does not provide value. The NEIL commitment is met by documenting the differential pressure during monthly tasks.

A 10-year search of plant-specific operating experience was performed to determine if NMP1 has noted any age-related degradation. No failure was identified. Specifically, no flow blockage, loss of material, or any other age-related degradation of the strainers was identified.

In addition, the station performs several inspections and tests that would identify flow blockage or fouling in the system due to strainer aging. The station performs annual fire pump performance tests where the differential pressure across the strainers is measured against acceptance criteria and the station performs system flow tests that measure and trend hydraulic conditions through the various flow loops. Deviations from acceptance criteria and adverse trends are captured and evaluated in CAP. In addition, the station performs monitoring and removal of sediment in the fire pump suction bays each refueling outage in accordance with the requirements of NRC Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

Finally, the suction source of the fire pump does not necessitate additional inspections of the fire pump discharge mainline strainers. The fire pumps take suction from the fire pump suction bay below the operating floor of the screen house through suction strainers that are inspected every refueling outage. This bay is part of the larger network of suction bays consisting of reinforced concrete walls, floor, and a ceiling that is sealed off from sources of debris. Water from the lake is filtered through traveling screens before entering the suction bays which reduces debris.

Therefore, annual and post significant flow inspections of the mainline strainers are not required for an effective Fire Water System aging management program due to operating experience history that shows no age-related degradation, the configuration of the strainers where they are rotated to ensure they are not fouled, and the periodic performance of other tests and inspections that would be capable of detecting a change in condition of the strainers.

3. NUREG-2191, AMP XI.M27, Table XI.M27-1 recommends compliance with the requirements of NFPA 25, Section 7.2.2.3 performed annually and after each significant flow. NFPA 25, Section 7.2.2.3 requires the station perform annual private service main mainline strainer inspections.

Private service main mainline strainer inspections are not performed at a fixed annual frequency but instead are conducted at a frequency based on evaluation.
Program Element Affected: Detection of Aging Effects (Element 4)

Justification for Exception

Surveillance frequencies are maintained in accordance with the NRC-approved fire protection program (ADAMS Accession No. ML14126A003). All strainer

inspections were initially performed at an annual frequency. The frequencies were extended to two years after no change in inspection results and, after additional inspections, extended to five years as results remained unchanged. One strainer inspection was extended a third time to nine years, and another was extended a third time to eight years. These extensions were performed over approximately the last 25 years, and the inspection results justified the frequency extensions. Imposing an annual inspection frequency on these strainers would not improve aging management of the fire water system if the current inspection frequency is justified. The NFPA 25 recommended inspection intervals apply equal to new systems and existing systems where the interval is justified. The current extended intervals are justified by inspection results.

4. NUREG-2191, AMP XI.M27, Table XI.M27-1 recommends compliance with the requirements of NFPA 25, Section 13.2.5 and modifies the required test frequency. NFPA 25, Section 13.2.5 states: “A main drain test shall be conducted... at each water-based fire protection system riser to determine whether there has been a change in the condition of the water supply piping and control valves.”

The current NMP1 Fire Water System aging management program does not perform main drain tests. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Corrective Actions (Element 7)**

Justification for Exception

A similar exception was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the License Renewal of Clinton Power Station, Unit 1 (ADAMS Accession No. ML25238A215). The NUREG-2191, Revision 1, recommendation is unchanged from the recommendation documented in NUREG-1801, Revision 2 with LR-ISG-2012-02. The following NMP1 justification is consistent with that approved for Clinton Power Station.

The current NMP1 Fire Water System aging management program is effective at aging management of the fire water system without the addition of main drain tests because the current program implements various testing and inspections that achieve the intent of main drain testing.

The current NMP1 Fire Protection Program implements various testing and inspection requirements promulgated by NFPA codes, regulations, and insurers. The purpose of main drain testing is discussed in both NFPA 25 and the Nuclear Electric Insurance Limited (NEIL) Loss Control Manual (LCM) and both sources indicate that the intent of the test is to identify major obstructions. However, the two documents differ in the application of the requirement. The NFPA code does not include any allowances to the testing requirement because NFPA codes are written for general applicability (i.e., usage outside of the highly regulated nuclear industry) and, typically, the requirements apply to facilities that do not own and control the fire water supply from the water source to the individual suppression systems. The NEIL LCM, however, includes an allowance to omit main drain testing because the manual acknowledges, and allows the insurer to credit the unique conditions of the highly regulated nuclear power industry.

Both NFPA 25 and the NEIL LCM agree that the purpose of main drain testing is to identify major obstructions in the flow path which NFPA 25, Annex A, Section A.13.2.5 clarifies to mean “a dropped gate, a valve that is almost fully closed, or a check or clapper stuck to the valve seat.” These examples are not the result of age-related degradation or failures of passive components. It is also stated in Annex A that a satisfactory main drain test does not, necessarily, mean that the pipe is unobstructed and cannot be relied upon without additional verifications such as valve position inspections. In addition to the clarifications in the NFPA code, the purpose of main drain testing stated in the NEIL LCM Interpretation Guidance is to identify major blockage. Therefore, the NFPA explanatory material and the NEIL Interpretation Guidance agree that the intent of a main drain test is to verify valve alignment in the fire water supply. The intent is not to identify partial restriction of supply piping, which would be indicative of age-related degradation by the measurement of increased hydraulic resistance of the flow path.

While NFPA 25 and the NEIL LCM agree that the intent of main drain testing is to identify valve misalignment or other major obstructions, the application of the test differs between the two sources. The NEIL LCM, written specifically for the highly regulated nuclear industry, identifies the potential hazardous and unique challenges associated with performing main drain testing of nuclear power plant fire suppression systems and includes an allowance to omit main drain testing if one of three conditions is met. The first condition requires the performance of the following tests and inspections: fire water valve position verification, fire protection valve cycling, annual fire protection loop flow test, fire suppression water system flow test (with exceptions that maintain normally dry systems as dry), fire protection water system flush, hydrant flush, post indicator valve testing, and wet pipe, deluge, and preaction system inspections. The second condition is if the fire suppression system is fed from two or more directions (dual feed systems) such that the failure of one isolation valve will not impair the system and the long runs of pipe are flow tested under other surveillance. The third condition is that for single feed systems with multiple suppression systems on the same header, a main drain test of the most remote system will satisfy the main drain test for all systems on that header. The NMP1 Fire Protection Program satisfies the requirements of two of the NEIL allowance which exceeds the requirements. The NMP1 Fire Water System aging management program performs testing as required by the first condition, with the exception of the annual flow test which is performed every five years as required by Table XI.M27-1, and the design of the NMP1 fire water system feeds each suppression system from two directions. The testing and multi-direction fire water supply to each fire suppression system are acceptable alternatives to main drain testing.

By review of the friction loss equations, the capability of main drain testing is limited to identification of major obstructions because the flow rates achieved during main drain testing are relatively low due to the small size of the main drain valves as compared to system supply headers and risers. As such, main drain testing is not an effective method to identify age-related flow blockage which typically results in partial restriction of supply piping and increased hydraulic resistance of the flow path due to fouling. While main drain testing is not an effective method to detect age-related flow blockage, the NRC-approved NMP1 Fire Protection Program includes full flow testing of the system supply headers

which would adequately identify partial restrictions of supply piping and increased hydraulic resistance of the system. The results of the systemwide flow testing are trended and compared to the system hydraulic analysis to ensure that adequate flow is available to fire suppression systems.

The NMP1 Fire Protection program manages the fire water supply and performs testing and inspections in accordance with its NRC-approved Fire Protection Program as supplemented by additional NEIL requirements. A 10-year search of plant-specific operating experience did not identify a history of major obstructions in fire water piping that would be detectable by main drain tests. Therefore, given the rigorous regime of alternative tests and inspections, the design of the system, and OE, reasonable assurance is provided that the Fire Water System aging management program is effective at identifying major obstructions without the addition of main drain testing.

5. NUREG-2191, AMP XI.M27, Table XI.M27-1 recommends compliance with the requirements of NFPA 25, Section 10.3.4.3 which requires the operational testing of water spray systems with either water or air to be performed on a frequency that is allowed by Table XI.M27-1 to be up to three years.

The NMP1 Fire Water System aging management program does not perform functional tests of the following deluge and spray systems:

- The two ventilation system charcoal filter spray systems.
- The 13 indoor spray systems.
- The west yard hydrogen rack deluge system.

The NMP1 Fire Water System aging management program performs a functional test of the following systems at an interval that exceeds the maximum frequency allowed by note 'n' in Table XI.M27-1.

- Three turbine building curtain deluge systems.
- Two transformer deluge systems.

Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6)

Justification for Exception

Surveillance frequencies for the two transformer deluge systems are established by the NRC-approved fire protection program (ADAMS Accession No. ML14126A003). The program will be enhanced to perform annual functional tests of the: 1) turbine building west wall water curtain, 2) turbine building south wall water curtain, and 3) turbine building south and east control building wall exposure above administration building roof deluge systems.

The NMP1 Fire Protection program does not functionally test the indoor spray systems, the ventilation system charcoal filter spray systems, or the hydrogen rack deluge system. The program does not need to be further enhanced

because the configuration of these systems, the existing inspections, and other enhancements ensure the effectiveness of the aging management program in managing the aging effects of these systems.

The indoor spray systems are constructed of galvanized steel pipe. There are no aging effects in NUREG-2191 for galvanized steel pipe exposed to indoor air. Aging effects are assumed due to the prescriptive nature of the NUREG-2191 AMP XI.M27 which requires the internal environment to be considered as condensation. These systems are not periodically wetted. There is no station OE of inadvertent action of these systems. External visual inspections are performed every two years which inspect the external conditions of the pipe and verify nozzle orientation. These external visual inspections would also identify leak-by in the control valve. Finally, these systems are included in the population of systems associated with the enhancement to require internal visual and nozzle inspections or alternative nondestructive examinations. The construction of these systems, operating experience, external visual inspections, and the enhancements to the program provide reasonable assurance that the AMP is effective in managing aging effects in these systems.

The NMP1 ventilation system charcoal filter spray systems are designed with at least two closed valves isolating the systems from the supply header. In each system, a tell-tale drain with a normally open drain valve is positioned between the two closed valves. The isolation valves are verified closed, the tell-tale drain valves are verified open, and the tell-tales are inspected for leakage quarterly. The systems are not subject to periodic wetting. A review of station operating experience identified no instances of inadvertent system actuation. The system is not subject to significant internal corrosion or flow blockage due to fouling since it is maintained dry and is not subject to periodic wetting during testing. The systems are designed and installed to allow for complete drainage. The nozzles are located inside filter housings which protect the nozzles from unplanned obstructions. In addition, these systems are included in the population of systems associated with two program enhancements. A similar exception was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Dresden Nuclear Power Station, Units 2 and 3 (ADAMS Accession No. ML25251A150). Finally, these systems are associated with two program enhancements. Periodic internal visual inspections or alternative NDE examinations will be performed and these systems are included in the enhancement to perform a one-time volumetric exam of normally dry systems.

The hydrogen rack deluge system is located outdoors and constructed of galvanized pipe. The system design and installation allow for the system to be completely drained. The system is not periodically wetted. There is no station OE of inadvertent action of the system. External visual inspections are performed every two years which inspect the external conditions of the pipe and verify nozzle orientation. These external visual inspections would also identify control valve leak-by. Finally, this system is associated with the enhancement to perform periodic internal visual inspections or alternative NDE examinations.

Therefore, the program does not need to be further enhanced because the configuration of these systems, the existing inspections, and other

enhancements ensure the effectiveness of the aging management program in managing the aging effects of these systems.

6. NUREG-2191, AMP XI.M27, Table XI.M27-1 recommends compliance with the requirements of NFPA 25, Section 14.2 which requires the performance of internal visual inspections and promulgates corrective actions to take when internal visual inspections identify foreign organic or inorganic material. Specifically, Section 14.2.2.2 of the 2011 Edition of NFPA 25 requires: “If the presence of foreign organic and/or inorganic material is found in any system in a building during the 5-year internal inspection of piping, all systems shall have an internal inspection.”

The NMP1 Fire Water System program will be enhanced to perform the internal visual inspections. However, an assessment will be performed instead of internal visual inspections of every system if a periodic internal visual inspection identifies foreign organic and/or inorganic material. **Program Element Affected: Detection of Aging Effects (Element 4)**

Justification for Exception

The requirement to perform an internal visual inspection of all systems when an inspection identifies foreign organic and/or inorganic material was revised in the 2014 Edition of NFPA 25 and the revised text has remained consistent through every edition since. The revised text is: “If foreign organic and/or inorganic material is found in any system in a building, all systems shall be assessed.” The substantiation for this change is provided in the NFPA “Technical Committee on Inspection, Testing and Maintenance of Water-Based Systems Report on Comments (ROC)” document. A summary of the discussions prior to voting on change is provided in the ROC. The substantiation for this change, which relates to changes to Section 14.2 as a whole, as stated in the ROC is as follows:

“This section has been changed and reorganized to allow for options when trying to determine the integrity of the fire protection system piping. The title was changed to more accurately describe that an assessment is now being required, and not just an internal pipe inspection. That assessment could include an internal pipe inspection, but it could also include alternative methods for checking for the presence of obstructing material that could affect the performance of the system in a fire event, as well as for corrosion that could affect the life span of the system. The frequency of the assessment can now be determined through a risk analysis which could determine that a longer frequency is appropriate, or that a shorter frequency is necessary, but if an approved risk analysis is not performed, the assessment must be performed every five years, with exceptions as provided”

In the 2011 Edition of the standard and all subsequent editions, the requirement of Section 14.2.2.2 to consider all systems has remained unchanged. It is the scope of evaluation type that has changed. In the 2011 Edition, all systems required an “internal visual inspection.” In the later editions, all systems are required to be “assessed.” NFPA 25 defines the assessment methods as including internal visual inspections, alternate means of inspection, and analyses.

Therefore, the intent is unchanged but the means to achieve the intent have been expanded to include more than internal visual inspections.

The enhancement to the NMP1 Fire Water System program includes the requirement to assess all systems if foreign organic and/or inorganic material is identified. Compliance with the 2014 Edition of the standard allows facilities with numerous suppression systems and robust corrective action programs to consider factors such as system time in service and the installation material and environment when developing an extent of condition evaluation plan. The NMP1 Fire Water System program consists of 57 in scope suppression systems that were placed into service on different dates, modified at different times during the course of operation, and constructed of different materials (e.g. carbon steel black pipe and galvanized carbon steel) in different environments (e.g. raw water and condensation). Constellation maintains a robust corrective action program that will be used to determine the appropriate actions during an extent of condition assessment of all systems when foreign material is identified during an internal visual inspection.

Therefore, the NMP1 Fire Water System program complies with the requirements of Section 14.2.2.2 of an alternate edition of NFPA 25, the 2014 Edition, rather than the edition that is recommended by NUREG-2191. The intent of the requirements of this section in the 2014 Edition is unchanged from the 2011 Edition and achieves an equivalent level of assurance that if foreign material is identified, the subsequent extent of condition assessment will assure the issue is not systemic to the system and the system is able to maintain its intended function.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements:

1. Perform a one-time volumetric wall thickness inspection test of a representative sample of sections of pipe that are periodically subjected to flow but are normally dry. The representative sample will be based on the population of system piping that is periodically subject to flow but is normally dry. The one-time volumetric wall thickness inspection test activity will include criteria for selection of inspection locations, acceptance criteria, and will specify the need for follow-up examinations based on inspection results. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6)**
2. Revise the hydrant flushing procedure to require hydrants be flushed for at least a full minute. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**
3. Perform system mainline strainer inspections after system operation or testing. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6)**

4. Perform, on a five-year frequency, internal visual inspections of every other in scope suppression system. These inspections will include nozzle inspections when performed on deluge systems. The systems not inspected in the first five-year interval will be inspected in the second five-year interval. In dry pipe systems and pre-action systems, the sprinkler removed for inspection shall be from the most remote branch line from the source of water that is not equipped with the inspector's test valve. Tubercles or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC). If the presence of foreign organic and/or inorganic material is found in any system in a building during the five-year internal inspection of piping, all systems shall be assessed. If the presence of sufficient foreign organic and/or inorganic material is found to obstruct pipe or sprinklers, an obstruction investigation will be conducted as described in Section 14.3 of NFPA 25. Alternatively, nondestructive examinations capable of ensuring flow blockage in piping and nozzles will not occur will be performed. The population of suppression systems eligible for inspection consist of the in scope wet pipe sprinkler systems, dry-pipe systems, preaction systems, and deluge systems that are not functionally tested.
Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6)
5. Perform two additional fire water system flow tests within the test interval (frequency) for each failed test. **Program Element Affected: Corrective Actions (Element 7)**
6. Perform a system mainline strainer inspection and cleaning after system flow exceeding that of a nominal two-inch orifice. **Program Element Affected: Detection of Aging Effects (Element 4)**
7. Perform annual functional tests of the: 1) turbine building west wall water curtain, 2) turbine building south wall water curtain, and 3) turbine building south and east control building wall exposure above administration building roof deluge systems. **Program Element Affected: Detection of Aging Effects (Element 4)**
8. Perform annual inspections of the two charcoal deluge system strainers and the strainer to the interior spray system manifold. **Program Element Affected: Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. One-time inspections will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Fire Water System program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In September 2025, an effectiveness review of the Fire Water System aging management program was performed in accordance with procedural

requirements. The review determined that the aging management program was effective in detecting aging effects and implementing preventive actions prior to a loss of function. The review found no discrepancies in the license renewal required scope. The review sampled entries in the corrective action program for SSCs within the scope of the Fire Water System aging management program. The review identified a single issue, presented as Operating Experience Example 5 below, and determined the in-place life cycle management plan is tracking resolution. The review conducted an OE search of the INPO OE database and the NRC website. The OE review concluded no enhancements were required. The effectiveness review concluded that the NMP1 Fire Water System aging management program is effectively managing the aging effects of in scope SSCs. This is maintained through walkdown visual inspections by the system engineer as well as a number of scheduled preventive maintenance tasks performed by various work groups like engineering, operations, and maintenance. The credited activities as well as the corrective action program and planned maintenance and testing have proven to be effective in maintaining and demonstrating system functionality.

The effectiveness review provides objective evidence that the Fire Water System program is effective and is informed and enhanced, when necessary, through the periodic internal review of program implementation. There is confidence that implementation of the Fire Water System program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

2. In September 2018, an effectiveness review of the Fire Water System aging management program was performed in accordance with procedural requirements. The review determined that the aging management program was effective in detecting aging effects and implementing preventive actions prior to a loss of function. The review found no discrepancies in the license renewal required scope. The review summarized the results of sprinkler testing where 27 of 28 sprinklers passed and a work order was created to replace all the sprinklers from the zone of the failed sprinkler. The review sampled entries in the corrective action program for SSCs within the scope of the Fire Water System aging management program and determined that, when an acceptance criterion was not met, there was no loss of function. All corrective actions were completed and/or scheduled in a timely manner. The review conducted an OE search of the INPO OE database and the NRC website. The review found that license renewal commitment implementing documents retained license renewal actions and were properly annotated.

The effectiveness review provides objective evidence that the Fire Water System program is effective and is informed and enhanced, when necessary, through the periodic internal review of program implementation. There is confidence that implementation of the Fire Water System program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

3. In July 2013, NMP1 performed an extent of condition review in response to NRC Information Notice 2013-06, "Corrosion in Fire Protection Piping Due To Air and Water Interaction," and documented the reviews in the corrective action program.

The result of the inspection resulted in an internally identified long term asset management (LTAM) item and system restoration procedure revisions. The LTAM item was initiated in October 2013. The LTAM summarizes the need to address the failure of multiple preaction systems due to tuberculation and obstructions. The LTAM references an adverse trend issue report, which observed recurring obstructions as far back as 2005, to justify needing to address the preaction system piping conditions. To resolve the issues, the LTAM presented several resolutions. Ultimately, the selected action was to replace preaction system piping. Replacement of the piping was completed in 2014. Since piping replacement and procedure modification, no additional CAP items have been created citing the identification of tuberculation in the preaction system piping.

This operating experience example provides objective evidence that NMP1 appropriately reviews and evaluates industry operating experience to ensure that lessons learned, and industry best practices are incorporated. This example also demonstrates that when issues that could potentially result in unacceptable conditions (e.g., improperly drained lines potentially resulting in accelerated corrosion and flow blockage) are identified, appropriate proactive corrective actions are taken.

4. In September 2020, several clogged nozzles were identified during performance of a transformer deluge system functional test. The clogging was immediately entered into CAP for resolution. The source of clogging was attributed to debris. All nozzles were removed, cleaned, and reinstalled. No analysis or additional information to clarify the source of the debris was summarized in the OE. The actions taken to remedy this issue were consistent with the requirements of the first license renewal aging management program. For SLR, the program is enhanced to include obstruction investigation requirements in accordance with the recommendations of Table XI.M27-1 when obstructions are identified.

This operating experience example provides objective evidence that NMP1 Fire Water System program implements testing that is capable of identifying and correcting aging of the fire water system.

5. In June 2025, a fire header leak outside the Unit 1 storeroom was identified and isolated. The leak was detected first by a fire header pressure low alarm and an electric fire pump #1 running alarm received in the main control room. Operators were dispatched to investigate, and the fire header pressure was found to be oscillating indicating a possible leak. Field investigations identified an exterior leak, and the leaking section of the header was isolated. The fire protection personnel identified that the header isolation rendered in scope administration building fire water suppression systems non-functional and immediately initiated compensatory measures in accordance with the station "Compensatory Measures for Inoperable Fire Protection Systems and Components" procedure. The area around the leak location was excavated for further evaluation and the failure was identified as a hole located on the underside of the ductile iron cement-lined pipe. The interior of the pipe was noted to be in good condition with no notable damage. Corrosion was identified on the exterior of the pipe, and the hole was noted to have a smaller opening on the interior of the pipe than the exterior. A portion of pipe was removed from the excavated hole and sent for

further failure analysis and to confirm as-found findings. From this analysis, failure was attributed to exterior pitting. The cement lining was determined to be intact and well adhered. Soil samples of deposits near the breach analyzed and the deposits exhibited a large concentration of chlorine and a small peak of sulfur. The analysis also states: "Additional OD deposits were pulverized followed by adding a few drops of concentrated acid. A faint rotten egg odor was detected, indicating that some of the sulfur was present as sulfides. Sulfides can be associated with microbiologically influenced corrosion (MIC), but there was no other strong evidence that MIC was occurring." Recommended actions include performing an extent of condition review following receipt of the lab analysis, repair of the affected section of pipe completed in July, and the creation of the long cycle management plan to begin replacement of fire main piping pending results of the extent of condition review and lab analysis.

This operating experience example provides objective evidence that condition monitoring elements credited by the Fire Water System program, in the form of control room alarms, are effective at identifying conditions in the fire header that may be age-related. This OE example also provides objective evidence that the station maintains an effective procedure use and adherence program and an effective corrective action program which determines the extent of condition when failures occur. Finally, this OE example demonstrates that the station is projecting the need to replace additional sections of fire header pipe and working to achieve funding for the replacement prior to additional loss of function.

The operating experience relative to the Fire Water System program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material, flow blockage due to fouling, and cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Fire Water System program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Fire Water System program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Fire Water System program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.17 Not Used

B.2.1.18 Fuel Oil Chemistry

Program Description

The Fuel Oil Chemistry aging management program is an existing mitigative and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The Fuel Oil Chemistry program manages loss of material in copper alloy, carbon steel, cast iron, nickel alloy, and stainless steel piping, piping components, and tanks with a fuel oil environment. The program also manages cracking, blistering, and loss of material in fiberglass tanks. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil. Fuel oil quality is maintained by monitoring and controlling fuel oil contaminants in accordance with ASTM guidelines. Fuel oil analyses that do not meet acceptance criteria are evaluated in accordance with the corrective action program. If analysis of fuel oil indicates biological activity or evidence of corrosion, then the need for biocide or corrosion inhibitor addition is evaluated.

The fuel oil tanks within the scope of license renewal are uncoated. Fuel oil tanks are periodically drained of accumulated water and sediment, cleaned, and internally inspected. The internal surfaces of the fuel oil tanks will be visually inspected, and volumetrically examined if degradation is observed, at least once during the 10-year period prior to the subsequent period of extended operation. During the subsequent period of extended operation, the tanks will be inspected at least once during each 10-year interval. Degradation of tank internal surfaces that does not meet acceptance criteria is evaluated in accordance with the corrective action program. Tank inspection results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. These activities effectively manage the effects of aging by identifying age-related degradation and maintaining potentially harmful contaminants at low concentrations.

The Fuel Oil Chemistry program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are generally applicable to all Constellation plants, with certain aspects limited to operation beyond 60 years. The equivalent Fuel Oil Chemistry program for Peach Bottom Atomic Power Station, including the aspects of the program applicable to operation beyond 60 years, has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Fuel Oil Chemistry program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Fuel Oil Chemistry aging management program will be consistent with the ten elements of aging management program XI.M30, “Fuel Oil Chemistry,” specified in NUREG-2191 with the following exceptions:

Exceptions to NUREG-2191

1. The NUREG-2191 Chapter XI.M30, “Fuel Oil Chemistry,” aging management program recommends periodic draining of water collected at the bottom of fuel oil tanks to minimize the amount of water and the length of contact time.

The emergency diesel generator fuel oil storage tanks and diesel driven fire pump fuel oil storage tanks do not have bottom drains where water can be periodically drained from the tanks. **Program Element Affected: Preventive Actions (Element 2)**

Justification for Exception

The program provides for periodic sampling/analysis of in-scope fuel oil tanks for water. Should water be detected during sampling and analysis, corrective action is initiated to remove the water from the tank.

The samples of the emergency diesel generator and diesel driven fire pump fuel oil storage tanks are obtained either as transfer pump samples or as tank samples. Pump samples are taken from the discharge of the fuel oil transfer pump where the foot valve on the pump suction is located six inches above the bottom of the emergency diesel generator fuel oil storage tanks and four inches above the bottom of the diesel driven fire pump fuel oil storage tank. The samples are not combined with oil samples taken at higher levels in the tank. This methodology obtains samples which are more likely to contain higher concentrations of contaminants, water, and sediment which tend to settle in the tank. Therefore, the sample location and methodology are effective for determination of contaminants, water, and sediment in fuel oil and are more conservative than the “multilevel” sample methods described in ASTM D4057. A similar evaluation was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession No. ML20044D902).

During transfer pump samples, pre-conditioning of the oil sample due to operation of the transfer pump is not occurring. Once the pump has started, one liter is purged and the sample is then acquired. Pumping a liter purge from the tank for flushing is inconsequential with respect to contaminants, water, and sediment that are in the lower region of the tank where the sample is obtained.

Sampling can also be performed by lowering a sample thief to six inches above the tank bottom. Both thief samples and transfer pump samples are not intended to be bottom samples, rather, they are representative samples from low points in the tank. Once per refuel cycle, bottom samples are collected from the tanks with sample thieves that are lowered into the tanks until rested on the tank bottom in a near vertical position.

These activities ensure the amount and the length of contact time of water collected at the bottom of the tank is minimized.

2. The NUREG-2191 Chapter XI.M30, “Fuel Oil Chemistry,” aging management program recommends that fuel oil tanks be drained and cleaned, the internal surfaces visually inspected (if physically possible) and volumetrically inspected if evidence of degradation is observed during visual inspection, or if visual inspection is not possible.

The diesel driven fire pump fuel oil storage tank will not be internally inspected.

Program Element Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)

Justification for Exception

The diesel driven fire pump fuel oil storage tank is a double wall fiberglass tank that provides fuel oil to the diesel driven fire pump fuel oil day tank. The tank includes periodic sampling and analysis activities for water and sediment content, total particulate concentration, and levels of microbiological organisms, and corrective actions when acceptance criteria are not met. Chemistry sampling ensures that contaminants detrimental to the integrity of the storage tank are maintained within acceptance criteria. The interstitial space between the primary and secondary storage tank wall is equipped with a leak detection system that continuously monitors for inner tank leakage and alarms locally if leakage is detected prompting corrective action. The storage tank and transfer system include design features to preclude transferring unacceptable products from the storage tank to the day tank. The tank suction line foot valve is located four inches off the bottom of the tank and the transfer piping includes a y-strainer. These design features, in conjunction with tank chemistry sampling activities and continuous leak rate monitoring, provide aging management of the diesel fire pump fuel oil storage tank and ensures that the intended function of the diesel driven fire pump is maintained.

Enhancements

In the elements identified below, the Fuel Oil Chemistry aging management program will be enhanced to:

1. Perform periodic internal inspection of the emergency diesel generator fuel oil day tanks and diesel driven fire pump fuel oil day tank at least once during each 10-year period starting 10 years prior to the subsequent period of extended operation. Each tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, then these diesel fuel tanks will be volumetrically inspected. **Program Element Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**
2. Perform periodic (quarterly) sampling, analysis, and trending for water and sediment content, particulate concentration, and the levels of microbiological organisms for the emergency diesel generator fuel oil day tanks and diesel driven fire pump fuel oil day tank. The new sampling activities will include a sampling

methodology that includes a representative sample from a low point in the tank which will provide for a more conservative sample than the multilevel sampling techniques described in ASTM D4057. **Program Element Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), Corrective Actions (Element 7)**

3. Perform periodic (quarterly) sampling, analysis, and trending for the levels of microbiological organisms for the emergency diesel generator fuel oil storage tanks and the diesel driven fire pump fuel oil storage tank. **Program Element Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), Corrective Actions (Element 7)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Fuel Oil Chemistry program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed of the Fuel Oil Chemistry aging management activities. The program effectiveness review concluded that the Fuel Oil Chemistry program prevents the loss of material due to corrosion that may result from the introduction of contaminants into the station's fuel oil tanks. The aging management activities required by this program are consistently being performed and are effective in preventing age-related degradation and contaminants from entering station fuel oil tanks. When age-related degradation is suspected, the condition is evaluated and corrected within the corrective action program. The results of the effectiveness review elements were as follows:

Program Effectiveness: The program is effective in preventing age-related degradation and contamination in fuel oil storage tanks. Required aging management activities are consistently performed, and any suspected degradation is evaluated and corrected through the corrective action program.

Detection of Aging Effects: All required inspections, tests, and preventive maintenance (PM) tasks are performed as scheduled. The program follows ASTM standards (D0975, D1796, D2276, D4057) and NUREG-1801 Section XI.M30. Biocides, stabilizers, and corrosion inhibitors are added to all incoming fuel deliveries, contrary to the Fuel Oil Chemistry aging management program description in the UFSAR License Renewal Supplement. An action was created to delete the exception regarding the use of biocides, stabilizers, and corrosion inhibitors from the UFSAR supplement for this program. The review of chemistry data from November 2018 to September 2025 identified no action level

exceedances for diesel fuel in the emergency diesel generator fuel oil storage tanks. Instances of elevated particulates and water were found in the diesel driven fire pump fuel oil storage tank which resulted in the generation of tank cleaning work orders.

Corrective Actions: Multiple issue reports (IRs) documented out of specification conditions for incoming diesel fuel. In all cases, the incoming diesel fuel was either rejected or the bulk storage tanks were verified to have not been impacted. Several IRs were written to document diesel driven fire pump fuel oil storage tank bottom sample failures. These samples indicated the presence of water and/or particulate above acceptance criteria. As a result, work orders were generated to clean the tank.

Operating Experience: Industry experience with water intrusion and particulate contamination was identified. At NMP1, water intrusion and particulate contamination is monitored monthly, and failures have not been identified. In cases where increasing trends were identified, cleaning of the diesel fuel was scheduled and implemented to prevent entering an action level.

A NUREG-1801, Revision 2 gap analysis was performed. NUREG-1801, Revision 2 recommends quarterly sampling for water, biological activity, and particulate contamination. Water and particulate contamination are monitored monthly at NMP1; however, biological activity is not. It was concluded that the Fuel Oil Chemistry program should be enhanced to align with the NUREG-1801, Revision 2 recommendation for quarterly sampling for biological activity.

License Renewal Commitment Management: All license renewal commitments are properly documented and maintained.

The effectiveness review provides objective evidence that existing aging management program activities are being effectively implemented to manage aging effects associated with a fuel oil environment, and that deficiencies identified during the implementation of the program are entered into the corrective action program for evaluation. Continued implementation of the program will ensure that components exposed to fuel oil within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

2. In August 2020, an IR was entered into the corrective action program to document fuel oil chemistry results from one of the emergency diesel generator fuel oil storage tanks. A sample was collected at the transfer pump suction level, approximately six inches from the bottom of the tank and an additional sample was collected at the bottom of the tank. The sample at the transfer pump suction level was satisfactory with no water or particulates found, however the bottom sample was positive for water and particulates. Per procedural guidance, an IR was entered into the corrective action program. A work order was generated, and the tank was cleaned.

This operating experience example provides objective evidence that fuel oil monitoring activities are effective in identifying fuel oil conditions not meeting station requirements, and that the corrective action program is effective in

evaluating the conditions to determine their impacts to system intended functions and in taking action to correct the unsatisfactory conditions.

3. In August 2016, an IR was entered into the corrective action program to document the results of a new fuel oil receipt sample. The sample failed the criteria for no water present and the delivery was refused. A replacement order was processed and the subsequent sample of the new delivery passed receipt inspection. The new delivery was off loaded into the fuel oil storage tank.

This operating experience example provides objective evidence that new fuel oil receipt inspections are effective in identifying out of specification fuel oil conditions to prevent contamination of onsite fuel oil storage and the corrective action program is effective in evaluating the conditions to determine their impacts to system intended functions.

4. In 2018, the Fuel Oil Chemistry aging management program 10-year drain, clean, and inspection was performed on an emergency diesel generator fuel oil storage tank. Tank internal cleanliness was documented as very good. Pictures were taken and sent to program engineering for review. No foreign material was found in the tank. Visual inspection of the tank did not find evidence of corrosion. Nondestructive examination was performed on the tank bottom. Three 12-inch by 12-inch grids were volumetrically examined and all as-found thickness measurements were acceptable.

This operating experience provides objective evidence that the Fuel Oil Chemistry aging management program is effective at managing fuel oil storage tank condition and maintaining the ability for the system component to meet its intended functions throughout the subsequent period of extended operation.

The operating experience relative to the Fuel Oil Chemistry program did not identify any adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including corrosion. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Fuel Oil Chemistry program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Fuel Oil Chemistry program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Fuel Oil Chemistry program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.19 Reactor Vessel Material Surveillance

Program Description

The Reactor Vessel Material Surveillance aging management program is an existing condition monitoring program that manages the loss of fracture toughness due to neutron embrittlement of the ferritic reactor pressure vessel (RPV) beltline materials in a reactor coolant and neutron flux environment. 10 CFR Part 50, Appendix H, requires that peak vessel neutron fluence at the end of the design life of the RPV will not exceed 1.0×10^{17} n/cm² (E>1 MeV), or that RPV beltline materials be monitored by a surveillance program to meet ASTM E185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." NMP1 is projected to achieve approximately 67 effective full power years (EFPY) of operation at the end of the subsequent period of extended operation. The RPV beltline materials of the NMP1 RPV will have received in excess of 1×10^{17} n/cm² (E >1 MeV) prior to the end of the subsequent period of extended operation. The NMP1 peak inside surface (0T) neutron fluence at the end of the subsequent period of extended operation is projected to be 3.23×10^{18} n/cm² (E>1 MeV) and the peak neutron fluence at ¼ of the vessel thickness from the inside (1/4T) at the end of the subsequent period of extended operation is projected to be 2.11×10^{18} n/cm² (E>1 MeV).

NMP1 is currently participating in an Integrated Surveillance Program (ISP) which has been approved for the first license renewal period of extended operation. For the subsequent period of extended operation, NMP1 will implement the guidance in BWRVIP-321, Revision 1-A, including the alternate withdrawal schedule in Appendix F consistent with the NRC's approval (ADAMS Accession No. ML22290A191).

The NMP1 Reactor Vessel Material Surveillance aging management program will implement the approved guidance for the subsequent license renewal BWR ISP in BWRVIP-321, Revision 1-A, which meets the requirements of 10 CFR Part 50, Appendix H. The program uses the increase in the Charpy V-notch 30 ft-lb transition temperature and the drop in the Charpy V-notch upper shelf energy (USE) to monitor the effect of reduction in fracture toughness due to neutron irradiation embrittlement.

The NMP1 Reactor Vessel Material Surveillance aging management program will rely on the BWRVIP ISP host site (Peach Bottom, Unit 3) to withdraw representative surveillance capsules during the subsequent period of extended operation per the approved schedule of BWRVIP-321, Revision 1-A, with a neutron fluence between one and two times the projected peak vessel neutron fluence that would be found at the end of the subsequent period of extended operation. Specific specimens representing NMP1 materials will then be tested. The peak reactor vessel neutron fluence of interest at the end of the subsequent period of extended operation addresses the time-limited aging analyses (TLAAs) described in the following sections of the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR), Sections 4.2.2.1.2, (Upper-Shelf Energy), 4.2.3.1.4 (Pressure Temperature Limits), 4.2.3.1.5 (Elimination of Boiling Water Reactor Circumferential Weld Inspection) and 4.2.3.1.6 (Boiling Water Reactor Axial Welds) for boiling water reactors (BWRs), as applicable.

The objective of the NMP1 Reactor Vessel Material Surveillance aging management program is to provide sufficient material data and dosimetry to monitor neutron

irradiation embrittlement and dosimetry during the subsequent period of extended operation. The ISP described in BWRVIP-321, Revision 1-A includes surveillance capsules installed in the host site reactor vessel with Charpy V-notch specimens and neutron dosimeters (flux wires). The surveillance capsules are withdrawn in accordance with the NRC-approved schedule to monitor the reduction in fracture toughness due to neutron irradiation embrittlement.

The NMP1 Reactor Vessel Material Surveillance aging management program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in upper shelf energy as a function of neutron fluence and irradiation temperature. Historical RPV beltline material test results provide reactor vessel material fracture toughness data for the neutron irradiation embrittlement time-limited aging analyses (TLAAs) (e.g., upper-shelf energy and pressure-temperature limits evaluations). The RPV beltline material test surveillance capsules are removed for monitoring and trending purposes and in conjunction with the NUREG-2191, AMP X.M2, "Neutron Fluence Monitoring." See SLRA Section 4.2 for the TLAAAs associated with neutron irradiation embrittlement.

Surveillance capsules shall meet the test procedures and reporting requirements of the applicable ASTM standards referenced in 10 CFR Part 50, Appendix H, to the extent practicable, for the configuration of the specimens in the surveillance capsule. Any changes to the surveillance capsule withdrawal schedule, including the incorporation and change of status of standby surveillance capsules to surveillance capsules scheduled for withdrawal and testing under this program must be approved by the NRC prior to implementation in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby surveillance capsules placed in storage are maintained for possible future insertion and tested specimens are retained in storage for possible reconstitution.

The Reactor Vessel Material Surveillance program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are generally applicable to all Constellation plants, with certain aspects limited to operation beyond 60 years. The equivalent Reactor Vessel Material Surveillance program for Peach Bottom Atomic Power Station, including the aspects of the program applicable to operation beyond 60 years, has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Reactor Vessel Material Surveillance program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Reactor Vessel Material Surveillance aging management program will be consistent with the ten elements of aging management program XI.M31, "Reactor Vessel Material Surveillance," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Reactor Vessel Material Surveillance program will be enhanced to:

1. Implement BWRVIP-321, Revision 1-A to maintain compliance with 10 CFR 50 Appendix H during the subsequent period of extended operation. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Reactor Vessel Material Surveillance program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, a program effectiveness review was performed of the aging management activities associated with the Reactor Vessel Material Surveillance aging management program. The assessment concluded that Reactor Vessel Material Surveillance aging management program was effectively managing the loss of fracture toughness due to neutron irradiation embrittlement in the RPV beltline material. The program activities include withdrawal and testing of a surveillance capsule from a host site, use of test results and allowable stress loadings for the ferritic RPV materials to determine operating limits, and comparison with a large industry data set to confirm validity of test results. It was determined that NMP1 was meeting the requirements of the aging management program and BWRVIP-86, Revision 1-A.

For the subsequent period of extended operation, the Reactor Vessel Material Surveillance aging management program will rely on the BWR ISP outlined in BWRVIP-321, Revision 1-A to withdraw and test the representative capsules with neutron fluence between one and two times the peak reactor vessel neutron fluence of interest at the end of the subsequent period of extended operation. Peach Bottom, Unit 3 will be a host site to withdraw a surveillance capsule per the approved schedule in BWRVIP-321, Revision 1-A, Appendix F. The capsules will be tested at a neutron fluence between one and two times the projected peak neutron fluence of interest at the end of the subsequent period of extended operation. Consistent with the alternate withdrawal schedule provided in BWRVIP-321, Revision 1-A, Appendix F, the scheduled withdrawal date for the representative capsules will occur at the host site's reactor vessel after NMP1 has entered the subsequent period of extended operation. The additional installation time is to ensure that capsules receive sufficient exposure to be

representative for all member sites. Tested or withdrawn capsules are placed in storage for future reconstitution and re-insertion.

This operating experience example provides objective evidence that self-assessments of the aging management program are performed to support continuous improvement.

2. In 2015, during the refueling outage, a reactor vessel surveillance capsule location at the 30 degree azimuth (30 degree capsule) was found dislodged from the vessel pad at the lower location. The specimen basket was not damaged, but the holder spring loading mechanism was degraded. The degraded spring mechanism prevented the specimen holder from proper engagement with the vessel bracket, thus creating the potential for the holder to become dislodged during operation. The 30 degree capsule could not be reinstalled because of the degraded spring mechanism and was, therefore, removed and stored in the spent fuel pool. The intention was for the capsule to remain in the spent fuel pool and ensure it was maintained in a condition that would allow re-installation at the next refueling outage. A letter was sent to the NRC detailing the finding, storage, and potential re-installation of the capsule (ADAMS Accession No. ML15191A165). Upon consultation with the EPRI/BWRVIP ISP program manager, it was determined that the reinstallation of the capsule was not required in either the initial 40-year term or in the ISP 60-year license renewal term. The capsule was not the original NMP1 reactor vessel surveillance capsule as it had been removed at the end of operating cycle 5 and then re-encapsulated and reinserted at the beginning of cycle 8. Additionally, the capsule was not required to support the NMP1 specific reactor vessel embrittlement program and did not provide the industry with data required by NMP1 or any other BWR. Testing of the capsule was not required to support the ISP. A follow-up letter was sent to the NRC detailing the decision to not re-install the capsule (ADAMS Accession No. ML16273A453). The capsule is maintained in the spent fuel pool, consistent with the NMP1 Renewed Facility Operating License, Item 2.H, and BWRVIP-86, Revision 1-A.

This operating experience example provides objective evidence that corrective actions are performed in accordance with BWRVIP guidelines upon identification of adverse conditions and regulatory notifications are made in a timely manner. This example also demonstrates that industry peers are actively involved in decision making which can impact other BWRs.

3. In 2025, an updated Pressure-Temperature (P-T) curve basis report was developed for 67 EFPY (80 years operation). The updated P-T curve basis report was established to the requirements of 10 CFR 50, Appendix G to ensure that brittle fracture of the reactor vessel is prevented by accounting for irradiation embrittlement effects. The methodology used to account for irradiation embrittlement is described in Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." New ART values were developed and based upon revised fluence projections and material information from the BWRVIP ISP. The projected fluence ($E > 1$ MeV) was calculated using the NRC-approved methodology in accordance with Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," independent of the P-T curve analysis. The latest information from the

BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program that was applicable to NMP1 was utilized including plant-specific and BWRVIP ISP material chemistries.

This operating experience example provides objective evidence that the program provides the necessary fluence and materials data to determine the effects of neutron fluence on limiting reactor vessel materials.

The operating experience relative to the Reactor Vessel Material Surveillance program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of fracture toughness. Appropriate guidance for evaluation is provided. Periodic assessments of the Reactor Vessel Material Surveillance program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the enhanced Reactor Vessel Material Surveillance program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Reactor Vessel Material Surveillance program will provide reasonable assurance that the loss of fracture toughness aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.20 One-Time Inspection

Program Description

The One-Time Inspection aging management program is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (1) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation; (2) the insignificance of an aging effect; and (3) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the program will include: (1) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (2) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, and (3) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (4) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the subsequent period of extended operation.

The program includes inspections that are focused on locations that are isolated from the flow stream, that are stagnant, or that have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. The inspections will include a representative sample of the system population (defined as components having the same 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. A technical justification of the methodology used for determining sample size and for selecting components for inspection will be included in the One-Time Inspection program documentation. The program either verifies that unacceptable degradation is not occurring, or it triggers additional actions that will ensure the intended function of affected components will be maintained during the subsequent period of extended operation.

One-time inspections that do not meet acceptance criteria are evaluated in accordance with the corrective action program. 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 inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections.

Periodic inspections instead of this program will be used for structures or components with known age-related degradation mechanisms or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The new One-Time Inspection program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new One-Time Inspection program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new One-Time Inspection program is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the new One-Time Inspection program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections will be completed within the 10 years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The One-Time Inspection aging management program will be consistent with the ten elements of aging management program XI.M32, "One-Time Inspection," specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. The NUREG-2191 Chapter XI.M32 "Parameters Monitored or Inspected," Table XI.M32-1 does not include inspection methods for the identification of loss of material due to wear on the external surface of components. The scope of the One-Time Inspection program includes the capability to perform visual inspections for wear on the external surfaces of components. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**

Justification for Exception

Recent fleet operating experience, as described in NRC Information Notice (IN) 2007-21, "Pipe Wear Due to Interaction of Flow-Induced Vibration and Reflective Metal Insulation," has demonstrated the potential for loss of material due to wear to occur on Class 1 small-bore piping exposed to end caps on reflective metal insulation (RMI). There is no operating experience demonstrating this aging effect at NMP1, and the One-Time Inspection aging management program will be

implemented to verify the aging effect is not occurring. A VT-3 or equivalent inspection will be performed to detect loss of material due to wear on the external surfaces of Class 1 small-bore piping exposed to RMI end caps.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the One-Time Inspection program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. Nine Mile Point Nuclear Station, Unit 1 has performed one-time inspections of various systems, structures, and components (SSCs) in which significant age-related degradation is not expected. These inspections were performed in order to fulfill first license renewal commitments. The first license renewal One-Time Inspection program included SSCs managed by this program as well as SSCs managed by other aging management programs for subsequent license renewal (e.g., ASME Code Class 1 Small-Bore Piping and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components). The following is a summary of the first license renewal one-time inspections results that are relevant to this program.
 - The material / environment group designated “GCI 1” consists of gray cast iron in air / moist air. The aging effect of concern was loss of material due to general corrosion. Four “more likely” locations were examined by VT-1. All inspections were completed satisfactory; therefore, no further inspections were required during the 20-year period of extended operation.
 - The material / environment group designated “CASS 3 & WASS 3” consists of cast / wrought austenitic stainless steel in treated water, temperature less than 140 degrees F, with or without flow, oxygenated or non-oxygenated. The aging effect of concern was loss of material due to crevice and pitting corrosion. Twenty-nine “more likely” locations were examined by VT-1 and VT-3. All inspections were acceptable; therefore, no further inspections were required during the 20-year period of extended operation.
 - The main condenser steam side and hotwell were selected for one-time inspection using VT-1 methodology under the “CLASL 6” sample group (carbon steel, low alloy steel, ductile or malleable iron with yield strength less than 100 ksi in treated water or steam, various temperatures, flow and no flow conditions). The aging effect of concern was loss of material due to general and crevice corrosion and pitting. The inspection, during the 2007 NMP1 refueling outage, discovered pitting and general corrosion at a vertical section weld. An issue report was written due to unacceptable inspection results. Based on this finding, 17 more locations were added for a second round of inspections, bringing the locations to 42. Repairs to the vertical weld section were made during the outage. A preventive maintenance activity had already been established in 2004 for technicians to walkdown and inspect the

main condenser hotwell every refueling outage. As a result of the one-time inspection results, a new preventive maintenance procedure was created to inspect and clean the steam side of condenser and hotwell every refueling outage.

- A 4 inch check valve was selected for one-time inspection using VT-1 and VT-3 methodology under the “WASS 3” sample group (wrought austenitic stainless steel in treated water less than 140 degrees F, various flow conditions, oxygenated or not oxygenated). The aging effect of concern was loss of material due to crevice and pitting corrosion. The inspection occurred during the 2007 refueling outage and yielded acceptable results. There was no crevice or pitting corrosion noted.

The operating experience relative to the One-Time Inspection program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of material, and long-term loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the new One-Time Inspection program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new One-Time Inspection program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.21 Selective Leaching**Program Description**

The Selective Leaching program is a new condition monitoring program. The program will consist of one-time and periodic inspections of sample components representative of the respective sampling population. One-time inspections will be conducted for components exposed to closed cycle cooling water or treated water environments since there is no prior plant-specific operating experience of selective leaching having occurred in these environments. Opportunistic and periodic inspections will be conducted for components exposed to raw water, waste water, and soil environments, as applicable. Periodic inspections will be conducted in the 10-year period prior to the subsequent period of extended operation and in each 10-year period during the subsequent period of extended operation. Opportunistic inspections will be conducted whenever components are opened or buried or submerged surfaces are exposed. Inspection sampling methodology will consider, where possible, factors of higher susceptibility such as time-in-service and severity of operating conditions for each population.

Components within scope of the Selective Leaching program include piping and piping components, valve bodies and bonnets, pump casings, heat exchanger components, and other components that are constructed of materials and are located in environments that may be susceptible to selective leaching. The materials of construction for these components are gray cast iron, malleable iron, ductile iron, and copper alloys containing greater than 15 percent zinc. Copper alloys containing greater than eight percent aluminum are also susceptible to selective leaching; however, there are no components in this program that are constructed of copper alloys with greater than eight percent aluminum at NMP1. The environments these components are exposed to are raw water, closed cycle cooling water, treated water, waste water, and soil (which may include groundwater).

The Selective Leaching program monitors visual appearance and surface conditions through visual inspections supplemented by mechanical examination techniques (such as chipping and scraping). Destructive and volumetric non-destructive techniques assess the presence and depth of dealloying through-wall thickness of components and allow for monitoring and projecting of rate of dealloying in susceptible components.

For the one-time and periodic/opportunistic portions of the program, visual inspections will be conducted on a representative sample of components of each material and environment combination of components. Ductile iron and malleable iron are considered a single material with respect to defining sample populations due to the similar morphology of these materials. A representative sample consists of three percent of each material and environment population or a maximum of 10 components per population. Additionally, for the periodic/opportunistic portion of the program, two destructive examinations will be performed for sample populations with greater than or equal to 35 susceptible components. When there are less than 35 susceptible components in a population, one destructive examination will be performed for that population. For gray cast iron, malleable iron, and ductile iron populations, volumetric non-destructive examination techniques may be performed in lieu of destructive examinations. The number of visual and mechanical inspections

may be reduced by two for each component that is destructively or non-destructively examined beyond the minimum number of destructive examinations recommended for each sample population subject to periodic inspections.

Inspections are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions as appropriate. Results will be evaluated against acceptance criteria to confirm that the sampling basis (e.g., selection, size, frequency) will maintain the components' intended function throughout the subsequent period of extended operation based on the projected rate and extent of degradation. The acceptance criteria are: (a) for copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color, green copper oxide, or white/gray mercuric deposit; (b) for gray cast iron, malleable 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, (c) the presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal, and (d) the components meet system design requirements such as minimum wall thickness, when extended to the end of the subsequent period of extended operation.

When inspection results determine that an affected component in a sample population does not meet the acceptance criteria such that it should be replaced prior to the end of the subsequent period of extended operation, additional inspections will be performed if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement of all components constructed of the same material and exposed to the same environment. The number of additional inspections is equal to the number of failed inspections for each material and environment population with a minimum of five additional visual and mechanical inspections when visual and mechanical inspection(s) identify selective leaching degradation which affects a component's ability to maintain its intended function through the end of the subsequent period of extended operation, or 20 percent of each applicable material and environment combination is inspected, whichever is less. A minimum of one additional destructive or non-destructive examination, as applicable for a component material of construction, will be performed when destructive or non-destructive examination(s) did not meet the acceptance criteria in addition to the number of failed non-destructive or destructive examination(s). If subsequent inspections do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections needed and/or corrective actions implemented in a component population.

In addition, when acceptance criteria are not met or inspection methods cannot positively classify selective leaching as the aging mechanism in a component (e.g., indefinite visual indications or surface conditions), a more capable examination technique (i.e., non-destructive and/or destructive examinations) will be performed to confirm the potential presence and extent of dealloying in a sampled component. Components constructed of gray cast iron, malleable iron, or ductile iron with identified dealloying through non-destructive examinations may be kept in service and re-examined during future inspections to allow for projection of the rate of dealloying, provided the component is conservatively determined to maintain its intended function through the next scheduled inspection.

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Selective Leaching aging management program will be consistent with the ten elements of aging management program XI.M33, "Selective Leaching," specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. NUREG-2191, aging management program XI.M33, Selective Leaching, Element 4 states "for sample populations with greater than 35 susceptible components, two destructive examinations are performed in each material and environment population in each 10-year period at each unit. When there are less than 35 susceptible components in a sample population, one destructive examination is performed for that population." The NMP1 program will allow performance of volumetric non-destructive examinations in lieu of destructive examinations for gray cast iron, malleable iron, and ductile iron populations. The number of non-destructive examinations will follow the guidelines for the required number of destructive examinations for each material and environment combination based on the number of components in the respective population. When this option is used, two volumetric examinations will be performed for each examination for which the new NDE technique is credited in lieu of a destructive examination recommended in NUREG-2191. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4).**

Justification for Exception

While destructive examinations provide more definite means to detect the presence and depth of dealloying in susceptible components compared to visual and mechanical examination techniques, these examinations eliminate the ability to periodically re-examine and monitor components undergoing selective leaching, and trend these findings for materials in similar environments and under similar operating conditions.

A component that has undergone selective leaching will develop a substrate that exhibits degraded mechanical properties, reduced density, changes in thermal conductivity, and different electrical and magnetic properties. Such changes in component material properties allow for NDE methods to detect and/or characterize the extent of selective leaching in components. EPRI research has demonstrated NDE as viable inspection method for the purpose of examining selective leaching degradation. Field-deployable ultrasonic and electromagnetic techniques have been shown capable of detecting and characterizing selective leaching in susceptible components, including cast iron pipe and valve samples. Demonstrated techniques which provide volumetric examination capability and where the technique has been optimized for the purpose of examining for

selective leaching, have been shown to provide comparable results to those provided by destructive examinations.

NDE techniques will allow for in-situ examinations for detecting and characterizing the depth of dealloying in susceptible components. This non-destructive methodology will provide the opportunity to re-inspect components experiencing this aging effect through subsequent inspections, providing enhanced understanding of degradation rate and projection of remaining component life through the subsequent period of extended operation as recommended by Element 5 of NUREG-2191, AMP XI.M33. Use of data encoders in these examinations will allow for storage of data and monitoring of degradation by comparing and analyzing degradation rates and behaviors through multiple inspections on the same component. Such techniques also allow for inspecting greater area of sampled components easier than through destructive examinations, which are limited to the section of component believed to be affected by selective leaching through visual indications. Furthermore, NDE provides a faster means of examining greater surface area and in analyzing the extent of condition in a component/ population. Such inspection results through NDE will provide valuable input for station personnel to better understand extent of condition in similar material and environment combinations and operational conditions. Thus, future sample methodology can also be improved to select components in populations more prone to selective leaching based on plant-specific environmental and operating conditions.

Volumetric non-destructive examinations performed as part of this program will employ techniques that have been demonstrated to be capable of detecting and characterizing selective leaching degradation. The Constellation process for use and implementation of a new technique will be followed prior to implementation of a new technique to meet inspection commitments for the Selective Leaching aging management program. This process will include a proof-of-concept (open or blind) demonstration to validate that the extent of selective leaching degradation is accurately characterized by the examination technique, a technical justification, and development of a technique specific procedure to conduct selective leaching examinations. This qualification methodology is equivalent to an Intermediate Rigor level of qualification of ASME Code Section V, "Nondestructive Examination," Article 14, "Examination System Qualification," however; the technique will be qualified for non-ASME Code components. This process will ensure that a new technique is capable of detecting and sizing dealloying within susceptible components prior to implementation of a new technique.

The inspection technique qualification process and documentation will include the applicability and limitations of the technique including the specific material type susceptible to selective leaching that may be inspected via the selected technique as well as other examination limitations (e.g., thickness, geometry). Therefore, while a specific technique is not specified herein, the technique qualification documentation will provide the applicability and limitations of the technique to ensure it is only used where supported by technical justification.

The use of volumetric NDE will be implemented for selective leaching inspections where appropriate and justified as described above; however, destructive

examinations may still be preferred by the site based on several factors, including planned component replacements and the feasibility of inspecting components within certain sample populations through NDE (e.g., due to accessibility issues). Therefore, while the program will allow for the performance of volumetric NDE in lieu of all destructive examinations, the NMP1 program is expected to rely on destructive examinations for certain populations.

Performance of two volumetric examinations as an alternative to each replaced destructive examination provides further assurance that selective leaching will be adequately managed. A similar exception was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Dresden Nuclear Power Station, Units 2 and 3 (ADAMS Accession No. ML25251A150).

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Selective Leaching program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. The Selective Leaching program is a new condition monitoring program for NMP1. Industry operating experience that forms the basis for this program is included in the operating experience element of the corresponding NUREG-2191 aging management program descriptions. Plant-specific operating experience was reviewed to ensure that the operating experience discussed in NUREG-2191 Chapter XI.M33 Selective Leaching aging management program is bounding (i.e., that there is no relevant plant-specific operating experience in addition to that described in NUREG-2191).

The Selective Leaching program for first license renewal included one-time inspections in the applicable material and environment combinations within the scope of the program. Four sample groups were established for the one-time inspections. The one-time sample inspections that were performed are as follows:

- Copper alloys in treated water. Seven component inspections were performed for this sample group. Components inspected included heat exchanger tubes/tubesheets and valves. All inspections were performed by using visual inspections, with one hardness test performed on a heat exchanger tubesheet. No indications of selective leaching were identified in this sample group.
- Copper alloys in raw water. This sample group included 18 inspections, primarily of valves and one heat exchanger. All inspections were performed using visual inspections. No indications of selective leaching were identified in this sample group.

- Gray cast iron in treated water. This sample group included inspection of 14 components, which included inspection of pump casings, valves, and piping components. Visual inspections were performed in addition to scraping for some components. Inspections did not reveal indications of selective leaching.
- Gray cast iron in raw water. This sample group included inspection of 15 components. Components inspected included pump casings, valves, heat exchanger end bells, and piping components. Visual inspections were performed supplemented by scraping, for some of the components. In addition, hardness testing was performed on two of the components inspected. No evidence of selective leaching was identified during these inspections.

Based on the one-time inspections performed on the sampled components for first license renewal, no degradation was found attributed to selective leaching, and, therefore; no further inspections or ongoing monitoring program for selective leaching was necessary at NMP1. A search of the NMP1 corrective action program was performed to determine if selective leaching has been cited. No occurrences of selective leaching were identified in an extensive search of NMP1 historical information and operating experience.

The operating experience relative to the Selective Leaching program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Selective Leaching program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Selective Leaching program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new Selective Leaching program will provide reasonable assurance that the loss of material aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.22 ASME Code Class 1 Small-Bore Piping

Program Description

The ASME Code Class 1 Small-Bore Piping aging management 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 nominal pipe size (NPS) 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. Destructive examination methods may be performed in lieu of volumetric examination. The program examinations are performed to verify that degradation is not occurring and to validate the effectiveness of existing programs and practices, thereby confirming that no additional aging management is required for the subsequent period of extended operation. The extent and schedule for volumetric examination is based on NMP1 plant-specific operating experience which reveals that cracking of a Class 1 small-bore weld has occurred. The program provides for a one-time examination of a sample of the total population of butt welds and periodic inspections of a sample of the total population of socket welds based on NUREG-2191, Chapter XI.M35, "ASME Code Class 1 Small-Bore Piping," Table XI.M35-1, "Examinations." Review of NMP1 operating experience identified no history of age-related ASME Code Class 1 small-bore piping butt weld failures, and one unmitigated ASME Code Class 1 small-bore piping socket weld failure that occurred in 2006.

In regard to socket welds, NMP1 submitted Licensee Event Report (LER) 2006-001-00, "Technical Specification Required Shutdown due to Increased Drywell Leakage," on August 10, 2006. Investigation of the failure discovered on the 'B' recirculation pump loop drain line found the cause to be due to vibrational fatigue. The failed drain valve and adjacent welds were replaced. There has been no additional cracking or through-wall leak events on the Unit 1 ASME Code Class 1 small-bore piping socket welds. Because this failure was not mitigated via a design change, this program implements a sample size and schedule for periodic inspections every 10 years, with the first inspections to be completed within six years prior to the subsequent period of extended operation for the populations of socket welds in Unit 1 as specified in NUREG-2191, Chapter XI.M35, Table XI.M35-1. Non-destructive and destructive testing will determine whether age-related cracking is occurring in the total population of susceptible ASME Code Class 1 small-bore piping welds.

In regard to butt welds, due to no history of age-related failures, this program implements a sample size and schedule for one-time inspections to be completed within six years prior to the subsequent period of extended operation for the populations of butt welds in Unit 1 as specified in NUREG-2191, Chapter XI.M35, Table XI.M35-1.

If one-time inspections identify unacceptable age-related cracking based on evaluation of the flaw performed in accordance with ASME Code, Section XI, IWB-3132, then periodic examinations will be performed on 10 percent of the

applicable weld population, up to a maximum of 25 welds per population. If required, periodic examinations will be performed on a 10-year frequency.

The following Table provides a summary of the number of one-time and periodic inspections required for full penetration (butt) welds and partial penetration (socket) welds, based on the comprehensive review of plant OE which revealed one unmitigated socket weld failure and identified no history of failures for butt welds:

Unit	Type of Weld (Butt or Socket)	Table XI.M35-1 Category	Percent/Number Requiring One-Time Inspection	Number of Welds in Population	Number of Inspections Required
1	Butt	A	3% up to 10	26	1 (one-time)
1	Socket	C	10% up to 25	1,248	25 (periodic)

The new ASME Code Class 1 Small-Bore Piping program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new ASME Code Class 1 Small-Bore Piping program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos.50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new ASME Code Class 1 Small-Bore Piping program is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the new ASME Code Class 1 Small-Bore Piping program will adequately manage the effects of aging such that intended function(s) are maintained consistent for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections will be completed within the six years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The ASME Code Class 1 Small-Bore Piping aging management program will be consistent with the ten elements of aging management program XI.M35 "ASME Code Class 1 Small-Bore Piping," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following example of operating experience provides objective evidence that the ASME Code Class 1 Small-Bore Piping program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

A comprehensive review of operating experience was completed for NMP1 identifying one ASME Code Class 1 small-bore socket weld age-related failure discussed below. There were no ASME Code Class 1 small-bore butt weld age-related failures identified. The methodology used to research the extensive operating history for NMP1 was by way of searching the NRC Licensee Event Reports database and plant library archives published prior to 1976 going back to 1969 to obtain the full plant operating history.

1. In 2006, increasing drywell leakage was identified. The condition of the leak worsened and resulted in exceeding the Technical Specification unidentified leakage limit of two gallons per minute increase in a 24-hour period, requiring the unit to shutdown on June 11, 2006. Licensee Event Report 2006-001-00, "Technical Specification Required Shutdown due to Increased Drywell Leakage," was submitted on August 10, 2006.

A root cause investigation determined the most likely cause was due to a valve packing leak. A contributing cause was due to an adjoining socket weld failure in the ASME Code Class 1 "B" recirculation pump loop 1-inch inboard drain line. The ASME Code Class 1 socket weld failure was attributed to vibrational fatigue and a potential original fabrication defect at the root of the weld. Small-bore socket weld failures resulting from vibrational fatigue have occurred in the industry on numerous occasions as documented in EPRI Technical Report TR-107455, "Vibration Fatigue of Small-Bore Socket-Welded Pipe Joints." The packing leak was repaired, and the affected piping was replaced.

The cause of this failure was not mitigated by an engineering design change, but the station did implement a valve packing program which eliminated chronic valve packing leaks and replaced all of the affected piping.

The operating experience relative to the ASME Code Class 1 Small-Bore Piping program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Code Class 1 Small-Bore program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that the implementation of the ASME Code Class 1 Small-Bore Piping program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new ASME Code Class 1 Small-Bore Piping program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.23 External Surfaces Monitoring of Mechanical Components

Program Description

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that will consist of visual inspections that are performed during system inspections and walkdowns. The program will consist of periodic visual inspections of metallic, elastomeric, polymeric, and cementitious components such as piping, piping components, ducting, ducting components, and other components within the scope of license renewal. The program will manage aging effects through visual inspection of external surfaces for evidence of loss of material of metallic components, loss of material and cracking of cementitious piping, loss of material, cracking, blistering, hardening and loss of strength for elastomers and polymers, and reduced thermal insulation resistance. Visual inspections will be augmented by physical manipulation to confirm the absence of hardening and loss of strength of elastomers. HVAC closure bolting is typically not associated with gasketed joints or flanges and is not subject to any appreciable preloads. Therefore, loss of preload is not an applicable aging effect for HVAC closure bolting. This program manages reduction of heat transfer due to fouling for heat exchanger tubes/fins not internal to components and exposed to outdoor air. This program will not manage reduction of heat transfer due to fouling for heat exchanger tubes/fins internal to components and exposed to air or condensation. This aging effect for this component type and environment will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program.

Inspections will be performed by personnel qualified in accordance with station procedures and programs to perform the specified task. When required by the ASME Code, inspections will be conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests will follow station procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, and presence of protective coatings. The inspections are capable of detecting age-related degradation and will be performed at a frequency not to exceed one refueling cycle. This frequency accommodates inspections of components that may be in locations normally accessible only during outages (e.g., high dose areas). Surfaces that are not readily visible during plant operations and refueling outages will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

Evaluations of as-found conditions will include confirmation that intended functions will be maintained given the projected degradation rate and the timing of subsequent inspections. Additionally, sample selection, size and frequency will be confirmed to maintain intended functions as applicable based on the projected degradation rate. Acceptance criteria will be defined to ensure that the need for corrective actions will be identified before loss of intended functions. For quantitative analyses, the required minimum wall thickness to meet the applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color and other indicators will be addressed.

Reduced thermal insulation resistance due to moisture intrusion, associated with insulation that is jacketed, will be managed by visual inspection of the condition of

the jacketing when the insulation has an intended function to reduce heat transfer from the insulated components. Component surfaces that are insulated and exposed to condensation (because the component is operated below the dew point), and insulated outdoor components, will be periodically inspected every 10 years during the subsequent period of extended operation by removing insulation and inspecting the metal surfaces for evidence of corrosion. Inspections will be conducted of each material type and environment in a sampling approach where condensation or moisture on the surfaces of the component could occur routinely or seasonally. A minimum of 20 percent of the piping length, or 20 percent of the surface area for components whose configuration does not conform to a one-foot axial length determination (e.g., valve body) will be inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components for each material type will be inspected. If the initial representative inspection verifies no loss of material beyond that which could have been present during initial construction, then subsequent inspections will consist of inspection of the external surface of the insulation for indications of damage or evidence of water intrusion through the insulation to the component surface. If insulation damage or evidence of water intrusion through the insulation is identified, then periodic inspection of the component surface under the insulation will continue. Loss of material due to boric acid corrosion is not an applicable aging effect for NMP1.

This program does not manage cracking due to stress corrosion cracking (SCC) or loss of material in aluminum and stainless steel components exposed to air environments with the potential to contain halides. As discussed in SLRA Sections 3.1.2.2.16, 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, 3.2.2.2.10, 3.3.2.2.3, 3.3.2.2.4, 3.3.2.2.8, 3.3.2.2.10, 3.4.2.2.2, 3.4.2.2.3, 3.4.2.2.7, and 3.4.2.2.9, a review of plant operating experience has not identified the existence of these aging effects in aluminum and stainless steel components in these environments. Further, a review of NMP1 operating experience indicates that cracking of copper alloy with greater than 15 percent zinc is not occurring. Additionally, the specific aluminum alloys of components within the scope of this program were either evaluated to be non-susceptible to cracking or to be in environments which do not contain halides per the guidance in NUREG-2192. Therefore, one-time inspections will be performed for these material, environment, and aging effect populations under the One-Time Inspection (B.2.1.20) program to verify that these aging effects are not occurring. If cracking or loss of material is identified during the one-time inspections, periodic inspections will be performed under the appropriate aging management program, which may include this program, as applicable.

The new External Surfaces Monitoring of Mechanical Components program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new External Surfaces Monitoring of Mechanical Components program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos.50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new External Surfaces Monitoring of Mechanical Components program is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the

new External Surfaces Monitoring of Mechanical Components program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The External Surfaces Monitoring of Mechanical Components aging management program will be consistent with the ten elements of aging management program XI.M36, "External Surfaces Monitoring of Mechanical Components," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the External Surfaces Monitoring of Mechanical Components program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, during a Unit 1 main condenser circulating water system walkdown, corrosion and external coating degradation was identified on the numbers 11 and 12 circulating water pumps. The system manager performs periodic walkdowns of the circulating water system and inspects for any degraded external conditions. Historically the circulating water pumps have presented external surface corrosion due to the wet environment, and the components were coated in 2010 to address this condition. The external condition of the coating is monitored and trended, and corrosion has been observed in areas where the coating is degrading due to the wet environment. The pumps remain functional with the corrosion; however, a work order was created to address the corrosion and degraded coating. This corrective work order is approved to replace the corroded circulating water pump base bolting, clean, and recoat the circulating water pumps and is planned for an upcoming outage.

This operating experience example provides objective evidence that periodic walkdowns are an appropriate method for monitoring and identifying corrosion of external metallic surfaces, and that the use of the corrective action program is an effective process for documenting identified deficiencies.

2. In 2024, during operator rounds, a visual inspection of the area cooler drain pan in the Unit 1 turbine building vent exhaust system was blocked due to rust. The rust was causing a blockage in the drain line, resulting in an overflow. Immediate

action was taken to clear the rust from the drain which mitigated the blockage and brought the drain back to service. Further maintenance was done to fully clear and resurface the drain.

This example demonstrates the method of identifying degraded equipment and that the corrective action program is an effective tool for documenting degraded conditions and establishing appropriate corrective actions.

3. In 2019, a routine visual inspection was completed on a standpipe from the main fire header to the fire hydrant and the associated isolation valve. The inspection determined that the pipe coating remained in good condition, and no cracks or leaks were observed.

This operating experience example provides objective evidence that routine visual inspection of system components is an effective method for monitoring external conditions of plant system components to prevent material loss, and that the use of the corrective action program is an effective process for documenting and trending inspection findings.

The operating experience relative to the External Surfaces Monitoring of Mechanical Components program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material, cracking, blistering, hardening or loss of strength, and reduced thermal insulation resistance. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the External Surfaces Monitoring of Mechanical Components program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new External Surfaces Monitoring of Mechanical Components program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.24 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 a new condition monitoring program that will manage loss of material, recurring internal corrosion, and cracking of metallic components, as well as loss of material and hardening or loss of strength in elastomers, and cracking or blistering, loss of material, and hardening or loss of strength in polymers. Reduction of heat transfer and flow blockage will also be managed. This program will consist of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components and other mechanical components. Applicable environments include dry air, condensation, closed cycle cooling water, diesel exhaust, fuel oil, gas, lubricating oil, raw water, raw water greater than 140 degrees F, treated water, waste water, and waste water greater than 140 degrees F. Except for aging effects in elastomers and polymers, aging effects associated with components within the scope of the Open-Cycle Cooling Water System (B.2.1.11), Closed Treated Water System (B.2.1.12), Compressed Air Monitoring (B.2.1.14), and Fire Water System (B.2.1.16) programs are not managed by this program.

The program will manage cracking of stainless steel components exposed to raw water greater than 140 degrees F and waste water greater than 140 degrees F, and copper alloy components with 15 percent zinc or more components exposed to raw water and waste water by surface examination, VT-1, or volumetric inspections. Examinations or inspections are conducted on 20 percent of the surface area inspected unless the component is measured in linear feet, such as piping. Alternatively, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. Samples are taken from multiple locations to ensure that a representative sample is examined, focusing on components most susceptible to the applicable aging effect.

Internal inspections will be performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. Although Nine Mile Point Nuclear Station is a multi-unit site, activities under this program apply only to a single unit (Unit 1). At a minimum, in each 10-year period during the subsequent period of extended operation a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population are inspected.

Sample selection will consider component susceptibility to aging due to factors such as time in service and severity of operating conditions. An inspection of a component in a more severe environment may be credited as an inspection for the specified environment and for the same material and aging effects in a less severe environment. Additionally, similar environments can be combined into a larger population provided that the inspections occur on components located in the most severe environment. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program.

This program does not manage cracking due to stress corrosion cracking (SCC) or loss of material in aluminum and stainless steel components exposed to aqueous solutions and air environments containing halides. As discussed in SLRA Sections 3.2.2.2.4, 3.3.2.2.3, 3.4.2.2.2, 3.2.2.2.8, 3.3.2.2.8, and 3.4.2.2.7, a review of plant operating experience has not identified the existence of these aging effects in stainless steel and aluminum components in these environments. Therefore, one-time inspections will be performed for these material, environment, and aging effect populations under the One-Time Inspection (B.2.1.20) program to verify that these aging effects are not occurring. If cracking or loss of material is identified during the one-time inspections, periodic inspections will be performed under the appropriate aging management program, which may include this program, as applicable.

Inspections not conducted in accordance with ASME Code Section XI requirements will be conducted in accordance with plant-specific procedures which include inspection parameters such as lighting, distance, offset, and surface conditions. Evaluations of as-found conditions will include confirmation that intended functions will be maintained given the projected degradation rate and the timing of subsequent inspections. Additionally, sample selection, size and frequency will be confirmed to maintain intended functions, as applicable, based on the projected degradation rate. Acceptance criteria will be based upon component, material, and environment combinations and ensure that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Quantitative analyses are used whenever practical with criteria such as the required minimum wall thickness to meet the applicable design standards being used. For qualitative evaluations, applicable parameters such as ductility, color, presence of cracks and other indicators will be addressed.

Additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the corrective action program; however, there will be no fewer than two additional inspections for each inspection that did not meet the acceptance criteria, or 10 percent of each applicable material, environment, and aging effect combination inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine any additional inspections needed. If any projected inspection results do not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the corrective action program.

The new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos.50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program will be consistent with the ten elements of aging management program XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed of the Preventive Maintenance Program described in UFSAR Section C.1.29. The purpose of the aging management program effectiveness review was to verify the intent of these initial aging management activities, which is to manage the aging effects of plant components determined to be within the scope of License Renewal and that require aging management but whose aging effects are not managed by other AMPs. The results of the effectiveness review were that the Preventive Maintenance program is effectively managing the aging effects of in scope SSCs to ensure a loss of function does not occur. A review of the program basis documents, the results of past inspections, and operating experience searches show that program compliance, management, and implementation all meet the requirements of the AMP.

This operating experience provides objective evidence of aging management program effectiveness through preventative maintenance during the first period of extended operation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program will effectively manage aging through preventative maintenance and periodic inspections such

that intended functions will be maintained through the subsequent period of extended operation. In addition, this example demonstrates that program effectiveness reviews are performed to drive continuous improvement of the program.

2. In 2023, an inspection of a condensate pump expansion joint was conducted and found the expansion joint in a degraded condition. This inspection included the internal and external visual inspection. No leakage was identified at any cracked location, but there was a partial collapse of the joint as well as rubber coating cracks in multiple locations. The subsequent evaluation determined that while the exterior coatings of the joint were degraded, the pressure boundary was still intact. Following this finding, the inspection was documented in the corrective action program, a work order was written to replace the expansion joint, and the expansion joint was replaced.

This operating experience example provides objective evidence that the aging management activities implemented by this program effectively monitor the associated SSCs to ensure the intended functions are maintained.

3. Between 2012 and 2022, multiple sections of city water piping were replaced due to through-wall leakage. The main failure mechanism causing the recurring internal corrosion was identified as microbiologically influenced corrosion (MIC). Out of the 1400 total linear feet of pipe, 770 feet has been replaced.

A minimum of five inspections will be performed for recurring internal corrosion every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for recurring internal corrosion as defined in SLRA Section 3.3.2.2.7. The selected inspection locations will be periodically reviewed to validate their relevance and usefulness and adjusted, as appropriate. Evaluation of the inspection results will include: (1) a comparison to the nominal wall thickness or previous wall thickness measurements to determine rate of corrosion degradation; (2) a comparison to the design minimum allowable wall thickness to determine the acceptability of the component for continued use; and (3) a determination of re-inspection interval.

This operating experience provides objective evidence that deficiencies are entered into the corrective action program and that appropriate corrective actions are taken to repair degraded plant equipment. Additionally, this example shows that age-related degradation of piping components is being managed.

The operating experience relative to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material, cracking, reduction of heat transfer due to fouling, flow blockage, hardening or loss of strength of elastomeric components, and cracking or blistering. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will effectively manage the effects of aging and initiate corrective actions

prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.25 Lubricating Oil Analysis

Program Description

The Lubricating Oil Analysis aging management program is an existing condition monitoring program that provides monitoring of oil condition to manage loss of material and reduction of heat transfer in piping, piping components, gear boxes, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. Sampling and analysis activities identify specific wear products and verify the contamination levels (primarily water and particulates) and the physical properties of lubricating oil are maintained within acceptable limits consistent with vendor or industry guidelines to ensure that component intended functions are maintained.

The program includes sampling, analyses, and trending activities which preserve an environment that is not conducive to loss of material or reduction of heat transfer. The lubricating oil sampling and analysis activities identify detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. Oil analyses that do not meet acceptance criteria are evaluated in accordance with the corrective action program. The contaminant levels are trended in the program's database, and recommendations are made when adverse trends are observed, which could include in-leakage and corrosion product buildup.

The program applies monitoring methods that are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent degradation that would affect a component's ability to perform its intended function.

NUREG-2191 Consistency

The Lubricating Oil Analysis aging management program will be consistent with the ten elements of aging management program XI.M39, "Lubricating Oil Analysis," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

1. Perform periodic sampling and testing of lubricating oil for moisture and corrosion particles in the liquid poison system pump gearboxes, following industry or vendor recommended practices. Alternatively, test old oil after periodic oil changes for the liquid poison system pump gearboxes based on vendor intervals or station experience. **Program Elements Affected: Detection of Aging Effects (Element 4)**
2. Perform periodic sampling and testing of hydraulic oil for moisture and corrosion particles in the circulating water gates and hoists system hydraulic fluid reservoir, following industry or vendor recommended practices. Alternatively, test old oil after periodic oil changes for the circulating water gates and hoists system hydraulic fluid reservoir based on vendor intervals or station experience. **Program Elements Affected: Detection of Aging Effects (Element 4)**

Operating Experience

The following examples of operating experience provide objective evidence that the Lubricating Oil Analysis program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In August 2019, an issue report was entered into the corrective action program to document a gap to excellence with oil analysis tracking and corrective actions. The issue report referenced missed sample results that were not noticed until the following sample results were obtained from the vendor. The gap to excellence and cause for not recognizing the missing oil analysis was identified as lack of a robust tracking method to ensure an analysis is received for all samples sent to the vendor. The fleet lubrication analyst peer group conducted informal benchmarking, and the issue was discussed on the bi-weekly managers call. Corrective actions to prevent recurrence were taken by adding a task to the work orders to notify the site lubrication analyst when samples were sent off site for analysis.

This operating experience example provides objective evidence that the Lubricating Oil Analysis aging management program is sensitive to learning from operating experience and self-improvement to ensure the proper analysis and trending of data is capable of recognizing a potential condition adverse to quality.

2. In March 2023, an issue report was entered into the corrective action program to document off-normal oil analysis for a circulating water pump. The sample results showed an increasing level of lead wear metal in the oil. All other parameters were within normal levels and trending steady. Circulating water pump bearing temperature trends were reviewed for the past seven years with no anomalies identified. The planned maintenance strategy for changing oil is based on the sample results and the lubricating oil analyst recommendation. This strategy would ensure the increasing lead wear metals do not impact long term reliability of the pump bearing.

This operating experience example provides objective evidence that the program provides for the periodic sampling, analysis, and trending of data and is capable of recognizing a potential condition adverse to quality and implementing appropriate corrective actions to evaluate out of tolerance oil parameters prior to failure or loss of intended function.

3. In March 2020, an issue report was entered into the corrective action program to document the latest routine oil analysis results for reactor recirculation motor-generator (MG) set which indicated elevated total acidity number (TAN). Per station oil analysis guidelines, the TAN exceeded the alert range. Despite the change, there was not an impact to functionality of the MG set, and no other parameters results were off-normal. Rising TAN, if left unaddressed, can cause an increase the viscosity of the oil. Oil analysis frequency was increased in accordance with procedural guidance to monitor for a continuing adverse trend. The oil was changed during the spring 2021 refueling outage. As a result, the TAN was restored to normal levels and the oil analysis frequency restored to normal routine sampling.

This operating experience example provides objective evidence that the program provides for the periodic sampling, analysis, and trending of data for monitoring the physical properties of oil in machinery and takes prompt action when parameters are not acceptable. The program facilitates prompt investigation to effectively manage aging prior to failure or loss of intended function.

The operating experience relative to the Lubricating Oil Analysis aging management program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Lubricating Oil Analysis program are performed to identify the areas that need improvement to maintain the quality performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Lubricating Oil Analysis program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Lubricating Oil Analysis program will provide reasonable assurance that the loss of material and reduction of heat transfer aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.26 Monitoring of Neutron-Absorbing Materials Other than Boraflex**Program Description**

The Monitoring of Neutron-Absorbing Materials Other than Boraflex aging management program is an existing condition monitoring program that includes periodic inspection, testing, monitoring, and analysis of test coupons of the neutron-absorbing material in the spent fuel storage racks to ensure that the required five percent subcriticality margin is maintained. This program consists of inspecting the physical condition of the neutron-absorbing material for visual appearance, dimensional measurements, weight, geometric changes (e.g., blistering, corrosion, and pitting), and boron areal density as observed from coupons or in-situ techniques, to monitor for reduction of neutron absorbing capacity, loss of material, and change in dimension.

The Monitoring of Neutron-Absorbing Materials Other than Boraflex aging management program monitors changes in physical characteristics of the material in the spent fuel storage racks through visual inspections, dimensional measurements, neutron-attenuation testing, weight, and density measurements of test coupons. The test coupons are made from the same material as used in the spent fuel racks. Results of each coupon surveillance are documented and retrievable. Acceptance criteria thresholds are established as indicators of potential adverse trends in the condition of the neutron-absorbing material to ensure corrective actions are taken prior to compromising the five percent subcriticality margin as contained within the spent fuel pool criticality analysis.

NUREG-2191 Consistency

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program is consistent with the ten elements of aging management program XI.M40, "Monitoring of Neutron-Absorbing Materials Other Than Boraflex," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2005, NMP1 spent fuel pool rack Boral coupon VN810735-2-1 was retrieved and analyzed in accordance with the NMP1 Boral surveillance program. Inspection of the coupon included visual examination for surface anomalies, imperfections, blistering or pitting, neutron-attenuation testing for boron-10

content, and weight/density measurements. Results from the post-irradiated coupon surveillance were compared to the original pre-irradiated data for evidence of blistering, swelling (bulging), loss of material, and decrease in boron-10 areal density to determine if there has been any loss of neutron-absorption capability. It was confirmed that no significant deterioration or degradation of boron areal density occurred, and each dimensional measurement was within the acceptance criteria.

2. In 2015, NMP1 spent fuel pool rack Boral coupon VN810430-1-1 was retrieved and analyzed in accordance with the NMP1 Boral surveillance program. Inspection of the coupon included visual examination for surface anomalies, imperfections, blistering or pitting, neutron-attenuation testing for boron-10 content, and weight/density measurements. Results from the post-irradiated coupon surveillance were compared to the original pre-irradiated data for evidence of blistering, swelling (bulging), loss of material, and decrease in boron-10 areal density to determine if there has been any loss of neutron-absorption capability. It was confirmed that no significant deterioration or degradation of boron areal density occurred, and each dimensional measurement was within the acceptance criteria.
3. In 2021, NMP1 spent fuel pool rack Boral coupon UN810074-3-3 was retrieved and analyzed in accordance with the NMP1 Boral surveillance program. Inspection of the coupon included visual examination for surface anomalies, imperfections, blistering or pitting, neutron-attenuation testing for boron-10 content, and weight/density measurements. Results from the post-irradiated coupon surveillance were compared to the original pre-irradiated data for evidence of blistering, swelling (bulging), loss of material, and decrease in boron-10 areal density to determine if there has been any loss of neutron-absorption capability. It was confirmed that no significant deterioration or degradation of boron areal density occurred, and each dimensional measurement was within the acceptance criteria.

These examples provide objective evidence that the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program effectively monitors the parameters that are indicators of the ability of the Boral to perform its intended function. The existing program contains acceptance criteria that will identify adverse trends in the Boral material neutron attenuation capability prior to a loss of intended function to ensure the assumptions in the spent fuel pool criticality analysis remain valid and the required spent fuel pool rack five percent subcriticality margin is maintained consistent with NEI 16-03-A, Revision 1, "Guidance for Monitoring of Fixed Neutron Absorbers in Spent Fuel Pools."

The operating experience relative to the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material, changes in dimension, and loss of neutron-absorption capacity of the material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Monitoring of Neutron-

Absorbing Materials Other Than Boraflex program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing Monitoring of Neutron-Absorbing Materials Other Than Boraflex program provides reasonable assurance that the aging effects and mechanisms are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.27 Buried and Underground Piping and Tanks

Program Description

The Buried and Underground Piping and Tanks aging management program is an existing condition monitoring program that manages the aging effects associated with the external surfaces of buried and underground piping and tanks including loss of material, cracking, hardening and loss of strength. It addresses piping and tanks constructed of any material, including carbon steel, polymers, copper alloys, fiberglass, asbestos cement, and cast iron.

The program manages aging through preventive and mitigative actions (i.e., coatings, backfill quality, and cathodic protection), relies on inspection activities, including visual examination of coated buried and underground piping and tanks, electrochemical verification of the effectiveness of the cathodic protection system, nondestructive evaluation of pipe or tank wall thicknesses, and performance monitoring of fire mains. The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. The cathodic protection survey results are evaluated using the -850mV relative to copper/copper sulfate reference electrode (CSE) instant off criterion specified in NACE SP0169, "Standard Practice – Control of External Corrosion on Underground or Submerged Metallic Piping Systems," to determine cathodic protection system effectiveness for steel piping and tanks. The program includes a limiting critical potential of not more negative than -1200mV on cathodic protection pipe-to-soil potential measurements of coated pipes to preclude potential damage to coatings. The program confirms cathodic protection effectiveness during the annual surveys through the use of corrosion probes.

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 projected to the end of the subsequent period of extended operation, an increase in the sample size will be conducted. Degraded conditions such as loss of material, damaged coatings, non-conforming backfill, or improper cathodic protection system voltage are evaluated under the corrective action program.

Aging management of the buried Fire Protection System piping will be accomplished through monitoring the activity of the diesel fire pump to detect system leakage.

This program does not address loss of material due to selective leaching. The Selective Leaching (B.2.1.21) program is used to manage loss of material due to selective leaching of susceptible materials.

NUREG-2191 Consistency

The Buried and Underground Piping and Tanks aging management program will be consistent with the ten elements of aging management program XI.M41, "Buried and Underground Piping and Tanks," specified in NUREG-2191 with the following exceptions:

Exceptions to NUREG-2191

1. The NUREG-2191 Chapter XI.M41, “Buried and Underground Piping and Tanks,” aging management program recommends visual inspections of buried polymeric piping in accordance with Table XI.M41-2. The buried polymeric piping will not be inspected. **Program Element Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4).**

Justification for Exception

The only in scope polymeric piping is the fiberglass reinforced plastic piping in the fire detection and protection system. The buried portions of this piping are entirely encased inside of a PVC pipe sleeve with the space between the pipe and sleeve filled with sand. A visual inspection of the PVC pipe sleeve does not provide any indication of the condition of the fiberglass reinforced plastic piping. In addition, aging effects typical to buried polymeric piping are minimized due to the protective outer PVC encasement piping. There is no identified operating experience of the failure of the encasement PVC piping at NMP1. A search of industry operating experience did not identify any failures of fiberglass reinforced piping encased in an outer PVC sleeve.

2. NUREG-2191 recommends backfill to be consistent with NACE SP0169-2007, Section 5.2.3 or NACE RP0285-2002, “Corrosion Control of Underground Storage Tanks Systems by Cathodic Protection,” Section 3.6. The NRC considers backfill that is located within six inches of a component that meets ASTM D 448-08, “Standard Classification for Sizes of Aggregate for Road and Bridge Construction,” size number 67 to meet the objectives of NACE SP0169-2007 and NACE RP0285-2002. For the diesel fire pump fuel oil tank and buried piping in the fire detection and protection system, the aggregate size meets the size specified in ASTM D 448-08; however, distance of the fill around the components is not specified. For the NMP1 emergency diesel generator system, the aggregate size meets the size specified in ASTM D 448-08; however, distance of the safety-related fill under the piping is four inches, which is shorter than the six-inch NUREG-2191 recommendation. **Program Element Affected: Preventive Actions (Element 2)**

Justification for Exception

For NMP1, multiple specifications were used for the backfill requirements around in scope buried piping and tanks. For the diesel fire pump fuel oil tank and buried piping in the fire detection and protection system, the tank bedding, piping bedding and tank/piping backfill is #1B screened gravel or stricter. The applicable standard has a size designation of 1/8-inch which meets the requirements of NACE SP0169-2007 and NACE RP0285-2002. The distance of fill around the piping and tank is not specified; however, both the tank and the piping are not directly exposed to the backfill. The piping has a protective PVC casing pipe, and the tank is a double wall tank. Backfill for the safety-related emergency diesel generator system fuel oil tanks and piping has a maximum size of 1/2-inch which meets the requirements of NACE SP0169-2007 and NACE RP0285-2002. The fill around the tanks meets the six-inch NUREG-2191 recommendation. The safety-related fill around the piping, except the area directly below the pipe, meets the six-inch requirement. The trench excavation

and safety-related fill was only required to be a minimum of four inches below the bottom of the pipe. This is not in compliance with the six-inch NUREG-2191 recommendation. There is no operating experience showing this configuration has resulted in degradation to the pipe. The difference between four inches and six inches is not expected to have any impact on damaging the coating on the piping.

Enhancements

In the elements identified below, the Buried and Underground Piping and Tanks aging management program will be enhanced to:

1. Perform one direct visual inspection of a 10-linear foot segment of buried carbon steel piping within the scope of license renewal during each 10-year period beginning 10 years prior to the subsequent period of extended operation. The number of inspections will be increased to six 10-linear foot segments of buried carbon steel piping within the scope of license renewal if either of the following criteria are not met for the cathodic protection system protecting the buried steel piping within the scope of license renewal:
 - a. System is maintained operational at least 85 percent of the time for 10 years prior to the subsequent period of extended operation (excluding time periods in which the cathodic protection system is off-line for testing).
 - b. System has provided effective protection for buried steel piping as verified through acceptable annual system testing results 80 percent of the time for 10 years prior to the subsequent period of extended operation. Testing results for cathodic protection systems protecting steel piping is acceptable if instant off potential is -850 mV or more negative, relative to a copper/copper sulfate reference electrode.

Program Element Affected: Detection of Aging Effects (Element 4)

2. Perform extent of condition inspections for steel piping as follows: When measured pipe wall thickness, projected to the end of the subsequent period of extended operation, does not meet the minimum pipe wall thickness requirements due to degradation of the external surface, the number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The scope of the follow-up inspections will be determined based on the analysis. Timing of any additional inspections will be based on the severity of the identified degradation and the consequences of leakage or loss of function. Any additional inspections will be performed within the same 10-year inspection interval in which the original degradation was identified, or within four years after the end of the 10-year interval if the degradation was identified in the latter half of the 10-year interval. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism or if the piping system or portion of the system is replaced or otherwise mitigated within the same 10-year inspection interval in which the original degradation was identified or within four years after the end of the 10-year interval, if the degradation was identified in the latter half of the 10-year interval. **Program Elements Affected:**

Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

3. Perform annual system monitoring of the cathodic protection system to ensure effective protection of buried piping with a grace period of up to two months. However, in each calendar year, system monitoring is conducted at least once.
Program Element Affected: Preventive Actions (Element 2)
4. Perform direct visual inspection of the in scope underground steel pipe and copper components located in the emergency diesel fuel oil valve pit during each 10-year period beginning 10 years prior to the subsequent period of extended operation. **Program Elements Affected: Detection of Aging Effects (Element 4)**
5. Perform direct visual inspection of the in scope underground fiberglass reinforced plastic and carbon steel piping located in the diesel fire pump tank access vault during each 10-year period beginning 10 years prior to the subsequent period of extended operation. **Program Elements Affected: Detection of Aging Effects (Element 4)**
6. Perform monthly monitoring of the fire system leak rate. The results will be trended to establish a baseline and indications of abnormal leak rate or increasing trends will be investigated in accordance with the corrective action program. If unexplained changes to the fire system leak rate are identified, then a flow test will be performed by the end of the next refueling outage. **Program Elements 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)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be performed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation, and no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Buried and Underground Piping and Tanks aging management program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed on the current Buried Piping and Tank Inspections aging management program described in UFSAR Section C.1.6. The effectiveness review concluded that the NMP1 Buried Piping and Tank Inspections program is effectively managing aging effects of license renewal in scope SSCs to ensure a loss of intended function does not occur. In scope systems for NMP1 License Renewal are Buried Fire Water and Emergency Diesel Generator Fuel Oil. All piping in scope for license renewal and NEI 09-14, "Guideline for Management of Underground Piping and Integrity," has been risk ranked per NEI 09-14 guidelines. NEI 09-14 focuses on assessing in scope components in order to provide reasonable assurance of

continued structural and leakage integrity. Nine Mile Point Nuclear Station, Unit 1 is taking additional actions to improve NEI 09-14 reasonable assurance documentation.

The results of the effectiveness review elements were as follows:

License Renewal Commitment Management: First license renewal commitments were reviewed and found that all implementation activities have been completed or are being performed at the periodicity prescribed by the license renewal commitment. No changes to the scope or frequency of the program inspections have been made. A sample of issue reports written on SSCs within the scope of the program were reviewed and found that corrective actions were completed satisfactorily. All commitments are properly documented and maintained. No changes have been made to the AMP commitments.

Corrective Actions: Corrective actions, including cause evaluations and prevention of recurrence, were reviewed for timeliness. The review found that there were no failed acceptance criteria. Review of the issue reports determined that the corrective actions, extent of conditions and further inspections were completed satisfactory. The review also determined that effects of aging are being identified and appropriately managed. A review of the corrective action database did not reveal any issues of aging related degradation in excess of what would be expected. This review demonstrated that the AMP is effective and did not identify any potential new aging effect or degradation mechanism. Only one significant degradation was found, which was a leak on the fire header. Soil conditions may have contributed; a soil survey was performed in May 2025, with results pending. All other corrective actions were timely and effective.

Operating Experience: Operating experience within the corrective action program relative to program activities was reviewed, including a review of industry operating experience going back to 2009. It determined that no changes or enhancements to the program were required. Industry and plant operating experience were reviewed. No changes or enhancements to the AMP were required based on external operating experience or lessons learned. No gaps were identified in the NUREG-1801, Revision 2 gap analysis.

Program Effectiveness: The effectiveness review validated that the first license renewal commitments were properly maintained and there were no changes to the commitments for the aging management program.

This operating experience example provides objective evidence of aging management program effectiveness during the first period of extended operation and provides objective evidence that the continued implementation of the program will effectively manage aging by identifying degradation prior to loss of intended function during the subsequent period of extended operation.

2. In 2024, a fleet self-assessment evaluating the performance of the buried piping program for each station was conducted. The assessment focused on procedural compliance, program implementation, program continuous improvement, program organization, and past program findings / deficiencies. The sites assessed were found to meet the procedural and programmatic requirements established to maintain a successful buried piping program.

Procedural compliance: The NMP1 buried pipe program assessment ensured that all procedures are up to date at NMPNS. Fleet subject matter expert (SME) updates the procedures as needed. The program notebook, long term asset management (LTAM) database, and inspection database have all been updated with current data.

Program Implementation: Risk ranking and prioritization does include the latest inspection results which are input and tracked in the inspection database MAPPro™. Actions were generated to ensure that the inspection data in MAPPro™ is periodically reviewed to reflect any changing conditions.

Program Continuous Improvement: The AMP/LTAM is updated annually and approved by plant health committee every two years. Program scope was evaluated in 2019 (NEI 09-14 Evaluation Project) and recommendations were captured in the corrective action program. Additionally, to ensure reasonable assurance is met a life cycle management issue was generated to cover all the necessary inspections.

Program Organization: Station management and fleet SMEs have been helpful to offer oversight and assistance to ensure the program implementation is successful. Challenges with continuity in knowledge and implementation have been observed due to high personnel turnover, but the strong fleet and station support has been instrumental in overcoming these challenges. Program interface with other station organizations has been effective through program owner communication/notifications and planned coordination meetings.

Program findings/deficiencies: No buried piping and tanks deficiencies were identified; however, the corrective action program is used to document issues for resolution. The recommendations identified in the 2019 evaluation were documented in the corrective action program and if there are any unsatisfactory results the program procedures will drive the use of the corrective action program to resolve the deficiency.

This operating experience example provides objective evidence that NMP1 critically self-assesses program performance and self-identifies actions that support continuous improvement.

3. In 2018, performance testing on the emergency diesel generator (EDG) fuel storage cathodic protection system failed the acceptance criteria. It was determined the cathodic protection system was still providing protection to the system but was in a degraded condition. A new work order was generated for a vendor to perform a study of the Unit 1 EDG fuel oil storage tanks to evaluate if and how additional anodes would be installed around the tanks. As a result of the evaluation, a project was initiated to upgrade the NMP1 cathodic protection (CP) system. The upgrade added eight 32 pound high potential magnesium anodes around each tank and one anode installed on each of the six pipe segments. The EDG fuel oil tank cathodic protection is provided without an external power source or rectifier. The driving voltage of the anode circuit is provided by the potential difference between the soil and the magnesium anode. NMP1 CP system performance since completion of the upgrade has met the CP system performance criteria.

This operating experience example provides objective evidence that measures to maintain and enhance the CP system are proactively implemented at NMP1 to ensure buried piping is adequately protected such that intended functions are maintained through the subsequent period of extended operation.

4. In May 2019, while performing emergency diesel fuel oil valve pit inspection degraded pipe coating was identified. Disbonding of the coating was observed on piping in the valve pit and vent piping for the EDG fuel oil tank along with small amount of water intrusion into the valve pit. The disbonding was not on in scope piping. To repair the degraded coating and prevent corrosion propagation to the in-scope system piping, the issue was entered into the corrective action program. It was determined that the condition did not require immediate repair; however, the piping in the vault would have a follow-up inspection performed on it. The piping was inspected in 2024, and the material condition of the coating did not significantly change since the previous inspection.

This operating experience example provides objective evidence that NMP1 has implemented a comprehensive buried piping inspection program that performs direct visual inspections on higher risk buried piping. This example demonstrates that this program implements inspection techniques that are capable of detecting age-related degradation prior to a loss of the component intended function.

5. In June 2025, an unexpected alarm was received for low fire header pressure. Fire pressure was found oscillating between 132 psig and 140 psig near the Unit 1 storeroom area, indicating a possible leak. Immediate actions were taken to isolate the leak. The issue was entered into the corrective action program, and a work order was generated to excavate, repair and identify the as-found condition of the fire service piping. The failed section of piping was replaced under a work order and saved for further analysis. Based on the condition of the external surface of the pipe, it was determined that the failure was likely corrosion from exposure to a pocket of water around the piping. The corrosion from the interior of the pipe was minimal compared to the external degradation. The failed section of pipe was sent to a laboratory for additional analysis, and a failure analysis report was provided to engineering. Additional actions are in progress to obtain funding for a project to replace additional sections of the underground fire service header.

This operating experience example provides objective evidence that NMP1 identifies adverse conditions with regards to the buried piping program in the corrective action program and takes appropriate follow up actions.

The operating experience relative to the Buried and Underground Piping and Tanks aging management program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of material, hardening and loss of strength. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Buried and Underground Piping and Tanks aging management program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating

experience. Therefore, there is confidence that continued implementation of the Buried and Underground Piping and Tanks aging management program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Buried and Underground Piping and Tanks program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.28 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 aging management program is a new condition monitoring program that performs periodic visual inspections of internal coatings/linings exposed to raw water, treated water, closed-cycle cooling water, waste water, air, and condensation. For buried cement lined fire water piping, opportunistic inspections will be performed in addition to flow tests and internal piping inspections at intervals specified in NFPA 25 and in accordance with the Fire Water System (B.2.1.16) program. There are no piping or components with internal coatings/linings in the program scope that are exposed to fuel oil, lubricating oil, or treated borated water. This program is not used to manage the integrity of coatings applied to external surfaces of piping or components.

The program complies with NRC Regulatory Guide (RG) 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants,” and applicable licensing basis requirements. Guidance contained in other industry documents, such as EPRI Report 1019157, “Guideline on Nuclear Safety-Related Coatings,” and ACI Standard 201.1R, “Guide for Conducting a Visual Inspection of Concrete in Service,” is also considered.

Other than for buried fire header piping, the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will include periodic visual inspections to verify the integrity of internal coatings designed to adhere to and protect the base metal. For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. Inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54. However, inspection intervals should not exceed those specified in NUREG-2191, AMP XI.M42, Table XI.M42-1, “Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.” For buried cement lined fire water piping, opportunistic inspections are performed.

Inspectors are trained and qualified in accordance with ANSI N45.2.6, “Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants.” The station coatings specialist will be trained and qualified in accordance with ASTM D7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist.” For cementitious coatings/linings, inspectors should 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. Inspection results that do not satisfy established acceptance criteria are entered into the corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected.

The program will be implemented through various station procedures and work activities. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. Peeling and delamination are not acceptable. Blisters are evaluated by a coatings specialist and should be limited to a few intact

small blisters that are completely surrounded by sound material, and with size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Coatings/linings that do not meet acceptance criteria are repaired, replaced, or removed. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing), or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompass sound coating/lining material. These inspections, and subsequent repairs, replacements, or evaluations of internal coatings will provide reasonable assurance that in scope components and downstream components will meet current licensing basis intended functions for the subsequent period of extended operation.

The following components are internally coated and are within the scope of subsequent license renewal due to potential for spatial interaction with safety-related SSCs. These components have been assessed using the guidance of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program and will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program as an alternative AMP for aging management:

- Reactor water cleanup (RWCU) system filter aid mix tank and filter precoat mix tank
- RWCU system cleanup pump oil reservoirs
- Condensate and condensate transfer system resin heater tank
- Makeup demineralizer system flush water tank

The new Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new Internal Coatings/Linings for in scope Piping, Piping Components, Heat Exchangers, and Tanks program is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the new Internal Coatings/Linings for in scope Piping, Piping Components, Heat Exchangers, and Tanks program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed within the 10 years prior to the subsequent period of extended operation,

and no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks aging management program will be consistent with the ten elements of aging management program XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

1. NUREG-2191, aging management program XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” recommends baseline inspections during the 10-year period prior to the subsequent period of extended operation and subsequent periodic inspections be performed for all tanks. The NMP1 condensate demineralizer tanks are internally coated/lined, however baseline inspections will be performed on two of the six condensate demineralizer tanks, which will be representative of the two types of coating systems installed among all six tanks. **Program Elements Affected: Detection of Aging Effects (Element 4)**

Justification for Exception

The NMP1 Condensate and Condensate Transfer System includes six mixed-bed demineralizer tanks. The demineralizer tanks are nonsafety-related components. The intended function of the tanks is (a)(2) functional since these tanks and associated piping are a portion of the flow path from the condenser to the reactor which supports the condensate/feedwater system high pressure coolant injection (HPCI) mode of operation.

The demineralizer tanks are carbon steel and were originally lined with a 3/16 inch rubber liner. Inspections of the original installed liner indicated cracking and presented potential loss of adhesion of the installed rubber. The rubber liners in all six demineralizer tanks have since been replaced due to aging of the original rubber lining and potential further loss of lining integrity. Demineralizer tanks (14, 15, and 16) were relined with a ceramic coating system in 2003. Demineralizer tanks (11, 12, and 13) were relined with an epoxy coating system in 2011. The tank surfaces were properly surface prepped, base metal inspected for age-related degradation and verified to meet design minimum wall thickness.

Environmental conditions were maintained throughout the coating application and coating thickness measurements taken to ensure proper coating application and curing. A spark test was performed following application of topcoat to verify no holidays in the new coating system. In 2009, an inspection of the #16 condensate demineralizer was performed where no aging effects or degradation of the new coating system were identified. In 2011, the #14 condensate demineralizer was opened to vacuum remaining resin and reduce radiation levels in the area in support of relining of the #11, 12, and 13 condensate demineralizers. While no formal coating inspection was performed, the #14 tank internals were observed by the system engineer, and no adverse conditions of

the coating system were noted. There have been no internal inspections performed on the #11, 12, and 13 condensate demineralizer tanks following installation of the new coating system. Nine Mile Point Nuclear Station, Unit 1 currently does not perform periodic internal inspections of these tanks.

Baseline inspections will be performed on two of the six demineralizer tanks such that each of the two types of coating systems (i.e. one inspection will be performed on the #11, 12, or 13 tank, and one inspection will be performed on the #14, 15, or 16 tank) are inspected prior to the subsequent period of extended operation. Performance of one inspection of each type of coating system installed among the six tanks will be representative of the condition of the other tanks with the identical coating system since each type of coating system was installed during the same period, with the same installation requirements, and the tanks experience the same operating conditions.

If the initial baseline inspection meets the acceptance criteria, one subsequent periodic inspection will be performed every six years during the subsequent period of extended operation for each set of demineralizer tanks with the identical coating system installed. A subsequent inspection will be performed on a tank not previously inspected with the same coating system such that all tanks will be inspected throughout the subsequent period of extended operation. If the initial baseline inspection does not meet the acceptance criteria, for a set of demineralizer tanks with the identical coating system, inspections will be performed on all other tanks with the identical coating system. Subsequent periodic inspections will be performed for that set of tanks as recommended in NUREG 2191, XI.M42 and Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

The six demineralizer tanks reside in a shielded room because of the high radiological dose associated with these tanks. Performance of a select representative set of inspections, as described above, provides reasonable assurance that any potential aging effects can be identified, while minimizing the radiological impact on personnel supporting inspection of these tanks.

The six condensate demineralizers are piped in parallel. The demineralizers may be isolated by valves upstream and downstream of each tank. Each of the demineralizer tank effluent passes through an externally mounted strainer, which is in scope with an intended function of "filter", located upstream of the main demineralizer outlet header. The strainer design includes a 250 micron stainless steel wire basket element, which prevent carryover of resin to downstream components. Each demineralizer is monitored for differential pressure, outlet conductivity, and integrated flow. Strainer differential pressure is monitored daily during operator rounds. If any coating were to come loose and be discharged from the demineralizer tank, the debris would be caught by the strainer element. Any indication of reduction of flow, increase in differential pressure and/or conductivity would be investigated to determine the cause and appropriate corrective actions, including inspections and repairs as necessary. In addition, it is not plausible that flow blockage due to demineralizer coating failure will result in reduction of flow to the degree below the required flow rate for the HPCI operating mode in the event of a small break loss of coolant accident event. The normal condensate and feedwater flow rate is much greater than the minimum

flow required for the HPCI operating mode which has been determined to be less than the normal flow rate of two demineralizer tanks. The demineralizer parallel flow paths allow for adequate flow margin such that downstream components necessary for the HPCI operating mode perform their intended function.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2021, during internal inspection of the #11 turbine building closed loop cooling heat exchanger, coating degradation was identified. The inspection identified several areas in the coating with degradation including blistering, cracking, flaking, missing coating, and surface rust. The issue was entered into the corrective action program. This heat exchanger is inspected annually, and similar coating degradation was identified during prior inspection. All areas of degradation were photographed and provided to engineering for evaluation and trending. Indications on the substrate were examined and verified to meet minimum wall thickness requirements. Engineering evaluated the as-found condition and determined that the degradation did not impact the component from performing its intended function.

This operating experience example provides objective evidence that internal coatings are inspected for degradation, and that adverse conditions are identified, evaluated, and addressed in the corrective action program.

2. In 2009, a vendor performed an internal inspection of the #13 condensate demineralizer and found three areas where a rubber lining repair was flaking off. The original rubber lining on the #11, 12, and 13 condensate demineralizers was evaluated, and it was recommended that the rubber linings in these tanks be replaced with a new coating system. Nine Mile Point Nuclear Station, Unit 1 accepted the recommendation, and the rubber lining was replaced with a new ceramic coating system in 2011. The original rubber lining was similarly replaced on the #14, 15, and 16 condensate demineralizer tanks in 2003.

This operating experience example provides objective evidence that internal coatings are inspected for degradation, and that adverse conditions are identified and addressed in the corrective action program to repair or replace degraded conditions.

The operating experience relative to the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of coating or lining integrity and loss of material. Appropriate guidance for evaluation,

repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will provide reasonable assurance that the loss of coating or lining integrity and loss of material aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.29 ASME Section XI, Subsection IWE**Program Description**

The ASME Section XI, Subsection IWE aging management program is an existing condition monitoring program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure-retaining components of steel containments for signs of degradation, damage, and irregularities. The program also includes visual examinations for distress of the underlying containment metal shell for coated areas. Corrective actions are performed in accordance with ASME Code requirements if unacceptable indications are identified during examinations. When conditions are found in accessible areas which indicate the presence of, or could result in, flaws or degradation in inaccessible areas, the acceptability of the inaccessible areas are evaluated. The scope of the ASME Section XI, Subsection IWE program is consistent with the scope identified in Subsection IWE-1000 and includes the Class MC pressure-retaining components and their integral attachments including wetted surfaces of submerged areas of the pressure suppression chamber and vent system, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metal.

The program includes condition monitoring by means of nondestructive examination (NDE) ultrasonic testing and visual inspections that provide reasonable assurance that the containment shell is not degrading and meets the acceptance criteria set forth in ASME Section XI. This program also includes aging management for the potential loss of material due to corrosion in the inaccessible areas of the BWR Mark I steel containment. Nine Mile Point Nuclear Station, Unit 1 currently performs visual inspections of the sandpocket area drains during refueling outages to confirm no leakage is occurring from the refueling seal. Additionally, NMP1 has committed to periodically perform boroscopic inspections of the drain lines to identify moisture and confirm no blockage on a 10-year frequency during the subsequent period of extended operation.

The program will be enhanced to perform a one-time surface examination or enhanced visual examination (i.e., EVT-1 exam) on accessible portions of a representative sample (i.e., 20 percent of population) of high-temperature drywell penetrations subject to cyclic loading or stress corrosion cracking (SCC) but have no current licensing basis (CLB) fatigue analysis (see Table 3.5.2.2.1.5-1 for total population). The program will also be enhanced to perform 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 metal shell that is inaccessible from one side, if triggered by plant-specific operating experience (base metal material loss exceeding 10 percent of nominal plate thickness over a local area as defined by ASME Section III 1965, Section N-513.3). A local area is defined as a circular area with a radius defined by one-half of the square root of the product of the containment metal shell diameter times the containment metal shell thickness at the location in question. Inspection results are compared with prior recorded results to monitor for degrading conditions and ensure that components remain acceptable for continued service. To date, NMP1 has not had any instance of plant-specific

operating experience which would have triggered this one-time supplemental volumetric examination.

The program includes aging management of steel and stainless steel surfaces and components such as the drywell shell and integral attachments, the torus shaped pressure suppression chamber, suppression chamber integral attachments, containment penetrations including flued heads, bellows and sleeves, containment hatches and airlocks, downcomers, moisture barriers, and pressure-retaining bolting for the aging effects of cracking, loss of preload, loss of material, loss of sealing, and loss of leak tightness in air (uncontrolled) and treated water environments.

The program is implemented through procedures, in accordance with the requirements of the ASME Code Section XI, Subsection IWE, supplemented with the applicable requirements of 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), the ASME Code, Section XI program code of record interval is updated each successive inspection interval (or two consecutive inspection intervals per 10 CFR 50.55a(y), as applicable) to comply with the requirements of the latest edition of the ASME Code specified eighteen months before the start of the inspection interval. The ASME Code edition consistent with the provisions of 10 CFR 50.55a will be used during the subsequent period of extended operation.

High-strength containment closure bolting susceptible to cracking is not used at NMP1; therefore, surface examination to detect cracking is not applicable.

The program utilizes inspections that detect degradation before loss of intended function. The program presently implements the requirements of IWE by providing visual examinations (General Visual and VT-3) and augmented inspections (VT-1) for evidence of aging effects that could affect structural integrity or leak tightness of the primary containment. Areas subject to augmented inspection are subject to visual inspection (VT-1) and volumetric (ultrasonic) examination techniques as required per IWE-1240. The program addresses the E-A, E-C, and E-G examination categories described in Table IWE-2500-1 and as approved per 10 CFR 50.55a. The program specifies examinations of accessible surfaces to detect aging effects as addressed in IWE-3500. The frequency and scope of examinations specified is in accordance with 10 CFR 50.55a, and ASME Section XI, Subsection IWE-2400.

The program complies with ASME Section, XI Subsection IWE for inspection of Class MC and metallic shell pressure-retaining components and their integral attachments, in accordance with the provisions of 10 CFR 50.55a. The monitoring methods have been demonstrated effective in detecting the applicable aging effects and the frequency of monitoring is adequate to ensure age-related degradation is identified and appropriate corrective actions are taken prior to loss of intended function.

The program provides for periodic inspections for the presence of age-related degradation on all accessible surfaces of the containment on a scheduled basis. When examination results require an evaluation or the component is repaired and is found to be acceptable for continued service, the areas containing such flaws, degradation, or repair are reexamined during the next inspection period, in accordance with Examination Category E-C.

The acceptance criteria for the ASME Section XI, Subsection IWE program, are in accordance with the requirements of the ASME Code, Subsections IWE-3000 and IWE-3500.

Indications are evaluated and compared to acceptance standards. Unacceptable conditions are recorded and documented in accordance with the corrective action program and supplemental examinations are performed in accordance with IWE-3200. Conditions which do not meet the acceptance criteria are accepted by an engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

Repairs and reexaminations, when required, are performed in accordance with IWA-4000 as required by IWE-3124 and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE-3500. Component re-examinations are conducted in accordance with the requirements of IWA-2200 and the results are recorded to demonstrate that the repair meets the owner defined acceptance standards per IWE-3500.

The ASME Section XI Inservice Inspection, Subsection IWE program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are generally applicable to all Constellation plants, with certain aspects limited to operation beyond 60 years. The equivalent ASME Section XI Inservice Inspection, Subsection IWE program for Peach Bottom Atomic Power Station, including the aspects of the program applicable to operation beyond 60 years, has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the ASME Section XI Inservice Inspection, Subsection IWE program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The ASME Section XI, Subsection IWE aging management program will be consistent with the ten elements of aging management program XI.S1, "ASME Section XI, Subsection IWE," specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. NUREG-2191 states that steel, stainless steel, and dissimilar metal weld pressure-retaining components that are subject to cyclic loading but have no CLB fatigue analysis, are monitored for cracking and are supplemented with surface examination (or other applicable technique) in addition to visual examination to detect cracking. Nine Mile Point Nuclear Station, Unit 1 has performed a fatigue waiver analysis in accordance with the ASME Code to demonstrate that the drywell and associated penetrations do not require a detailed fatigue analysis through the subsequent period of extended operation. This analysis does not include penetrations for high-temperature process lines as those penetrations will require aging management in accordance with the guidance in this AMP.

Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**Justification for Exception**

The NMP1 drywell contains components that are subject to cyclic loading but have no CLB fatigue analysis. The NMP1 primary containment was designed in accordance with ASME Section III, 1965 Edition. The 1965 Edition of the ASME Section III B&PV Code did not require fatigue analysis of Class B vessels. The drywell penetrations were considered an extension of the drywell and, thus, did not require fatigue analysis. Later analysis was performed for fatigue for the torus and torus attached piping. The torus shell, vents, downcomers, and torus attached piping and penetrations are analyzed in TLAA Section 4.6.1, 4.6.2, 4.6.3 and 4.6.5. NMP1 has performed an evaluation that demonstrated had the drywell shell and portions of drywell penetrations been designed to ASME Section III, 1974 edition with an expectation to operate for 80 years, then it would have met the criteria in subsection NE-3222.4(d), "Vessel not requiring analysis for cyclic operation." The criteria included: 1) atmospheric to operating pressure cycle, 2) normal operation pressure fluctuation, 3) temperature difference – startup and shutdown, 4) temperature difference – normal operation, 5) temperature difference – dissimilar metals, and 6) mechanical loads. The evaluation concluded that the components that could be subject to cyclic loading but have no CLB fatigue analysis can be considered exempt from further fatigue analysis. This evaluation excluded penetrations for high-temperature process lines.

The program will be enhanced to perform a one-time surface examination or enhanced visual examination (i.e., EVT-1 exam) on accessible portions of a representative sample (i.e., 20 percent of population) of high-temperature drywell penetrations subject to cyclic loading or stress corrosion cracking (SCC) but have no CLB fatigue analysis (see Table 3.5.2.2.1.5-1 for total population). The majority of the surface of these components are not accessible for visual inspection or surface examination for cracking due to the Mark I containment design. Three penetrations will be selected to represent the population of penetrations for high-temperature process lines which include the following:

- Main Steam: X-2A, X-2B
- Emergency Condenser Steam Supply: X-3A, X-3B
- Primary Feedwater: X-4A, X-4B
- Emergency Condenser Return: X-5A, X-5B
- Shutdown Cooling Return: X-7
- Shutdown Cooling Supply: X-8
- Cleanup Supply: X-9
- Core Spray: X-13A, X-14

A surface examination or an enhanced visual examination (i.e., EVT-1 exam) will be performed on the accessible portions of the high-temperature drywell piping penetration subject to cyclic loading. Original design and installation specifications for containment penetration components such as bellows, welds, and penetration adapters required initial surface examinations to ensure no flaws existed as part of initial installation. Appropriate integrated and local leak rate testing are conducted for pressure boundary components per the 10 CFR 50 Appendix J (B.2.1.31) aging management program. Through-wall cracking would be detected by the type A integrated leak rate test. Additionally, general visual examinations are performed on accessible portions of the containment penetrations in accordance with the IWE program. Nine Mile Point Nuclear Station, Unit 1 has not experienced a failure of the above listed containment components and integrated leak rate test results have shown satisfactory results. Industry operating experience has also shown strong performance of the subject primary containment components. Therefore, the existing 10 CFR Part 50 Appendix J leak testing and ASME Section XI, Subsection IWE, are adequate to detect cracking without requiring surface examination or enhanced visual examination for the containment components subjected to negligible or low levels of fatigue. A similar exception was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Dresden Nuclear Power Station, Units 2 and 3 (ADAMS Accession No. ML25251A150).

Enhancements

In the elements identified below, the ASME Section XI, Subsection IWE aging management program will be enhanced to:

1. Perform a one-time supplemental surface or enhanced visual examination (i.e., EVT-1 exam) on accessible portions of a representative sample (i.e., 20 percent of population) of high-temperature mechanical drywell penetrations subject to cyclic loading or stress corrosion cracking, to detect cracking. If cracking is identified as a result of these inspections, additional inspections will be conducted to increment the sample size by one additional penetration at a time from the uninspected population until cracking is no longer detected. The corrective action program will be used to determine the extent of further inspections, if necessary. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**
2. Implement a one-time supplemental volumetric examination of the containment metal shell surfaces that are inaccessible from one side, if triggered by plant-specific operating experience. The trigger for this supplemental examination is plant-specific occurrence or recurrence of containment metal shell corrosion (base metal material loss exceeding 10 percent of nominal plate thickness over a local area as defined by ASME Section III 1965, Section N-513.3) initiated on the inaccessible side or areas, identified since the date of issuance of the first renewed operating license. For the purposes of this enhancement, a local area is defined as a circular area with a radius defined by one-half of the square root of the product of the containment metal shell diameter times the containment metal shell thickness at the location in question. This supplemental volumetric examination consists of a sample of one-foot square locations that include both

randomly selected and focused areas most likely to experience degradation based on plant-specific operating experience and/or other relevant considerations such as environment. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically with 95 percent confidence that 95 percent of the accessible portion of the containment metal shell is not experiencing corrosion degradation with greater than 10 percent loss of nominal thickness. If required, the supplemental volumetric examinations will be completed within two refueling outages of identification of the triggering containment metal shell corrosion or sooner, as determined by the corrective action program based on the severity of the identified degradation. **Program Elements Affected: Detection of Aging Effects (Element 4)**

3. Provide guidance for 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 consistent with EPRI NP-5067 and TR-104213. Also, provide guidance for storage, lubricant selection, and bolting and coating material selection consistent with Section 2 of Research Council on Structural Connections (RCSC) publication “Specification for Structural Joints Using High-Strength Bolts.” **Program Elements Affected: Preventive Action (Element 2)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. The one-time supplemental surface or enhanced visual examination will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation. If required, the one-time supplemental volumetric examination will be performed in accordance with the schedule identified in the enhancement.

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI, Subsection IWE program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. An IWE AMP effectiveness review was performed in 2025 using Constellation procedural guidance and industry standards. The AMP effectiveness review assessed the key attributes of the existing ASME Section XI, IWE AMP effectiveness, including but not limited to detection of aging effects, corrective actions, evaluation of industry and plant-specific operating experience informing the AMP, and verifying license renewal commitments are properly maintained. The review concluded that inspections have been performed in accordance with specified commitment implementation activities (e.g., preventive maintenance tasks, walkdowns, inspections). No adverse trends or deficiencies were identified during the inspections or any previous corrective actions. The program was determined to be effectively managing aging in accordance with the existing 10 elements of the AMP.

This operating experience example provides objective evidence of aging management program effectiveness during the first period of extended operation. This example also demonstrates that periodic program effectiveness reviews are performed to ensure that program effectiveness is maintained and to drive continuous improvement.

2. A 2019 IWE visual inspection of the interior of the torus documented “tigerstripping” corrosion along the sidewalls. Tigerstripping corrosion is a pattern of vertical stripes below the waterline with black metal oxide ridges and bare metal valleys. The qualified inspectors in 2019 documented the approximate metal loss as pit gauge measurements from the top of the ridge to the bottom of adjacent valleys. The metal loss documented exceeded the IWE acceptance criteria of 10 percent wall loss in some locations, which required an engineering evaluation to disposition as acceptable. The evaluation concluded that the observed local pitting did not exceed the allowable pit depth, therefore, concluding that the condition was acceptable for continued service.

IWE Category E-C examinations were required in the next inspection period following the detection of conditions that fail to meet the acceptance standards of IWE-3513. The 2019 IWE inspection reported wall loss greater than 10 percent of nominal wall thickness in some areas of the torus. While the areas were evaluated as acceptable from a structural integrity standpoint, they did not meet the acceptance standards of IWE-3513. Table IWE-2500-1, Examination Category E-C requires a visual, VT-1 examination (Item E4.11) on surfaces that are considered accessible for visual examination on the side that is subject to degradation.

In order to satisfy the follow-up requirements of the IWE examination and also provide actual thickness readings, NMPNS requested approval from the ANII to perform a random sampling plan of ultrasonic thickness measurements under IWA-2240, “Alternative Examinations,” as allowed by IWE-2500(b)(3). In lieu of the VT-1 visual examinations required by IWE Category E-C, Item E4.12, NMP1 performed ultrasonic thickness examinations from outside the torus in 2023.

The ultrasonic thickness measurements confirmed torus structural integrity with the ASME Code required 95 percent confidence. The projected time to minimum wall thickness for all locations is at least 54 years. The vast majority of measurements were above 0.430 inches. In accordance with ASME Code, the random sampling plan locations require a follow-up exam of the thinnest documented grid in each location to confirm corrosion rate.

Follow-up exams are scheduled to be performed in 2027. Corrosion product analysis did not conclusively establish the corrosion mechanism of tigerstripping. While historical action by sulfate reducing bacteria (SRB) cannot be ruled out as a cause, there is no evidence of current SRB activity. Metallurgical testing did not identify any likely causes. The expanded monitoring of the torus wall thickness may inform future investigations of the corrosion mechanism.

This operating experience example provides objective evidence that the IWE program examinations performed by qualified personnel are capable of detecting damage to in scope components and other indications of possible age-related degradation, and that corrective measures to ensure the integrity of the

containment shell are implemented by the station. This example also demonstrates that deficiencies are entered into the corrective action program and that actions are taken to address deficiencies in accordance with ASME Code Section XI requirements.

3. During an IWE exam of the drywell shell moisture barrier in 2019, it was identified that the moisture barrier was showing signs of degradation. The moisture barrier prevents water intrusion at the joint interface between the drywell shell and the concrete floor and is located in the drywell at 225 foot elevation. The existing moisture barrier was replaced in its entirety in 2015. An issue report (IR) was created to document the seven areas of potential degradation and to assign subsequent actions to investigate and repair the areas of concern.

Upon further investigation by the responsible individual (RI), multiple areas had caulking peeling away from the shell, one location appeared to be a small gap in a length of 39.5 inches between the caulking and the shell, one area did not have caulking for a length of 9.5 inches, and a few areas had surface dirt. The assumed cause of the degradation in these areas was disturbance to the moisture barrier by physical abrasion likely from scaffolding or some such object during 2017. All the areas were found dry; therefore, the moisture barrier was still performing its design function to prevent water intrusion to the inaccessible surfaces below.

Based on the evaluation of the RI, the more severe areas were recommended for repair in 2019. While the remaining areas were excluded from repair due to being acceptable following a thorough surface cleaning, no indications were present.

A VT-1 exam was performed on the severe areas after the removal of the moisture barrier as the shell below these areas was found to be intact and unaffected. The subsequent VT-1 performed on these areas following repair was found to be acceptable.

A new moisture barrier was applied to the affected areas. The unaffected moisture barrier was inspected to ensure that no degradation (wear, damage, tears, surface cracks, or other defects) existed which would permit intrusion of moisture against inaccessible areas of the pressure retaining surfaces of the metal containment shell. The inspection was completed satisfactorily, and no recordable indications were identified. The new moisture barrier will prevent moisture from reaching the inaccessible region of the containment.

The moisture barrier was inspected again in 2023 and there were indications identified which did not meet the acceptance standards of IWE-3510. As a result, the degraded moisture barrier was removed and the area was cleaned to perform visual exams of the underlying metal shell, which identified pitting. NMP1 performed ultrasonic testing (UT) of the locations of concern to determine the extent of the degradation. The UT thickness readings were taken on clean base material around areas of pitting to evaluate extent of wall loss. It is noted that all UT readings taken just above the moisture barrier met or exceeded the nominal wall thickness requirements except one. The lowest drywell shell reading was 1.077 inches, and the drywell shell nominal thickness was 1.090 inches. However, the original design and construction of the drywell included a

0.0625 inch corrosion allowance, thus a minimal wall thickness requirement of 1.0275 inches. Therefore, even the lowest UT measurement taken meets the minimum wall thickness requirement. However, the NDE reports at the moisture barrier noted the presence of isolated areas of pitting that were unable to be measured with the UT equipment. The pitting most closely resembles that of a "hammered" finish, with smooth edges and a relatively shallow, uniform surface profile. It is noted that the location of the lowest UT reading is located within an area of this uniform pitting. Given the limitations of the UT equipment, the reading had to be made on a relatively flat surface within the pitted area. By observation, the pitting profile would result in a relatively nominal wall thickness change when compared to the measured thickness of 1.077 inches. This nominal change in wall thickness is considered acceptable given the fact that the lowest UT reading still maintains margin to the original design and construction corrosion allowance. NMP1 performed an evaluation in accordance with 10 CFR 50.55a(b)(2)(ix)(A)(2) to determine the acceptability of the inaccessible areas. NMP1 concluded that the shell and inaccessible area was acceptable for continued service and replaced the moisture barrier at the locations where it had been rejectable and removed. These locations will continue to be monitored by the ASME Section XI, Subsection IWE program.

This operating experience example provides objective evidence that the IWE program examinations can detect degradation in accessible areas which could lead to degradation of inaccessible locations. Nine Mile Point Nuclear Station, Unit 1 fully interrogated the situation by ensuring when the moisture barrier was removed, the underlying inaccessible containment shell was inspected. Proper installation of a new moisture barrier ensures that the function to prevent moisture intrusion is met. Additionally, this example highlights the practice of identifying deficiencies and entering them into the corrective action program. This ensures that appropriate actions are taken to evaluate and address deficiencies in accordance with ASME Code Section XI requirements and ensures that follow-up inspections are performed.

4. Nine Mile Point Nuclear Station uses three methods to manage aging on the Unit 1 torus. The first method uses ultrasonic measurements of specific predetermined grids on the torus exterior shell. In 1993, 40 grid locations were measured and compared to results taken in 1989 and the six locations with the worst corrosion rate were chosen to be monitored annually thereafter. The data is taken and used as an input to a calculation which processes the inspection results, compares them to minimum requirements and develops a corrosion rate.

The second method involves the weight and thickness analysis of material coupons to calculate corrosion loss and estimate corrosion rates relatable to the torus shell. Prior to 2015, the sampling was performed on a six-year frequency, currently three coupons are removed on an eight-year frequency from each of the four coupon holders. This change was made due to lower than expected corrosion rates found. The last sampling was performed in the 2023 refueling outage.

The third method is a visual inspection of the torus support structure for corrosion and any visible deficiency of the support structure. Inspections are performed during every refueling outage.

During the first license renewal, the NRC reviewed the existing program to determine if the program would effectively manage the aging effects imposed during the period of extended operation. The NRC reviewed AMP elements submitted in the license renewal application and determined that the program demonstrated the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB.

This operating experience example provides objective evidence that the in scope components subject to aging management per the IWE program receive additional supplemental inspections capable of detecting damage and other indications of possible age-related degradation, and that corrective measures to ensure the integrity of the containment shell are implemented by the station.

5. During the 2003 refueling outage, a general visual examination of the accessible portions of the interior surface of the drywell shell was performed. Six localized areas, near and underneath the drywell area unit coolers, were observed to have significant corrosion. In accordance with ASME Section XI, Subsection IWE, a detailed visual examination (VT-1) was performed of the six localized areas. The condition was entered into the corrective action program and an engineering evaluation was performed.

To determine the actual thickness of the drywell shell at these locations, the four most severe locations were chosen by the IWE responsible engineer to have UT examinations performed. The areas were prepped for UT examination using hand tools to prevent metal removal. The results of the UT examinations concluded that the measurements were all above the minimum design thickness value of 1.049 inches. An engineering calculation was performed that projected the time necessary to reach minimum design thickness of the drywell shell using the UT results and the originally assumed corrosion allowance of 62.5 mils over 40 years. It was determined that the minimum design thickness would not be reached until 2039, which was 10 years beyond the end of the first period of extended operation.

To ensure the drywell shell would continue to perform its intended function in the first period of extended operation, continued monitoring in addition to the ASME Section XI, Subsection IWE Program was required. A drywell supplemental inspection program was created; the scope of the program was to perform UT exams in the areas identified as having major corrosion on the drywell. The six areas were localized and located under the six drywell area unit coolers on the 225 foot and six inch elevation. The program determined the periodicity of inspection and corrective actions would be based on the corrosion rate found at the locations. The most probable cause of the degradation under the area coolers was due to the cleaning of the coolers with a solution of water and "coilex" during the performance of preventive maintenance on the coolers. Mitigative actions were completed to require protection of the drywell shell from liquids during the cooler cleaning maintenance activities.

During the 2007 refueling outage, an IR was initiated to document higher corrosion rates than expected on the drywell shell. Ultrasonic examinations were performed and compared to the values obtained in 2003. A best effort was made to duplicate the inspection locations, but the locations were not permanently

marked in 2003. This comparison resulted in a new conservative corrosion rate of 10.5 mils per year. At the new corrosion rate, the remaining time duration to reach the shell minimum design thickness was three to eight years. The license renewal commitment established in the drywell supplemental inspection program was to perform UT exams on a two-year frequency and implement a mitigative strategy. In order to trend the UT exam data in the future, four 10-inch by 10-inch grids with one inch spacing were marked on the shell to repeat the UT measurements during the 2009 refueling outage.

During the 2009 refueling outage, UT examinations were performed on the four grids established at the drywell area unit coolers. The corrosion rates found on the drywell shell exceeded the anticipated corrosion rate. However, when comparing photos of the area of the inspection from 2007 and 2009, it was noted that the locations were significantly cleaner in 2009 than in 2007 which would indicate that the data from 2007 may not have been accurate due to the poor condition of the surface and/or the preparation in 2009 may have been too aggressive. The second observation that was made was that there was virtually no change in the appearance of the areas surrounding the areas cleaned for the UT thickness measurements. Paint applied for various identification purposes outside of the areas cleaned for UT measurements can be seen virtually unchanged, indicating that general corrosion of the area was not occurring. The third observation that was made was the surface irregularities in the cleaned areas that affected the ability to obtain good surface contact with the UT probe and potentially affected the consistency of the readings. Given all of the above considerations it was concluded that the corrosion rates that could be calculated from the differences between the 2007 and the 2009 were not indicative of the actual corrosion taking place on the shell plates. The most likely explanation for the differences in UT thickness measurements was the aggressive surface preparation which could have removed metallic high spots on the surfaces and caused the UT readings to be artificially skewed.

It shall be noted that NMP1 has never identified evidence of drainage from the sandpocket drains. These drains have also been confirmed to be unobstructed and clear of debris during boroscopic inspections performed in 1991 and 2007. Therefore, it is concluded that there is no evidence of water running down the back of the shell that could lead to corrosion on the external side of the shell.

The calculation for the minimum design thickness of the shell was revised and the new expected time to reach minimum design thickness was extended to after the 2011 refueling outage.

In the 2011 refueling outage, UT examinations were performed at the grids previously established in 2007 near the drywell area unit coolers. The corrosion rates measured between 0.055 and two mils per year. The implementation of the UT grids has resulted in a more accurate corrosion rate and allowed the station to better replicate the exam in the future for trending purposes. The drywell supplemental inspection program required a mitigative strategy to be implemented if corrosion rates were greater than 1.26 mils per year. In order to satisfy the requirements in the supplemental inspection program and prevent future corrosion, the drywell shell was cleaned and recoated using service level one coatings in 2011. The entire perimeter of the 225 foot and six inch elevation

was recoated approximately six feet up the side of the shell. Each of the locations identified in the scope of the drywell supplemental inspection program were coated, effectively eliminating further corrosion of the shell on the inside surfaces of the drywell. The program was subsequently suspended, and inspections of the shell are now in accordance with the ASME Section XI, Subsection IWE program.

It should be noted that during the 2023 IWE inspections, multiple locations of the interior surface of the drywell shell were identified to show signs of blistering, peeled and complete loss of coatings with varying degrees of underlying base metal degradation. These recordable indications were identified in three different general locations, elevations 225 foot and six inch to 234 foot, elevations 234 foot to 260 foot, and the vent headers. Some of these locations required coating removal for inspection of the underlying area. After the worst areas were cleaned and coating removed, ultrasonic testing was performed to determine the extent of degradation. All ultrasonic testing identified adequate shell margin and acceptable results. Nine Mile Point Nuclear Station, Unit 1 has scheduled future actions to recoat the degraded areas of the drywell shell during the 2027 refueling outage.

This operating experience example provides objective evidence that the condition of the containment shell is actively monitored and inspected for evidence of corrosion. Additionally, corrective actions have been taken to ensure the drywell shell and moisture barriers are protected from liquid during cleaning activities on the drywell coolers. The current IWE program is being effectively implemented to manage aging effects. Continued implementation of the ASME Section XI, Subsection IWE aging management program will ensure that the potential for corrosion of the drywell shell is actively managed during the subsequent period of extended operation.

6. NRC Information Notice (IN) 2006-01, "Torus Cracking in a BWR Mark I Containment," was issued to alert licensees that a through-wall crack was discovered in a torus shell at a U.S. BWR. The issue was reviewed for applicability to NMP1, and the results were documented in the corrective action program. At the BWR where the cracking was found, the high pressure coolant injection (HPCI) system turbine exhaust line that discharges into the suppression pool is open ended and does not have an end cap or sparger to diffuse energy. The configuration of the HPCI exhaust was not reliable or sufficient and ultimately caused the cracking.

The NMP1 exterior support columns have a robust connection to the shell which includes both vertical and horizontal gusset plates that distribute the applied load to a larger surface area of the shell. The NMP1 torus is comprised of 20 segments whereas the BWR's torus discussed in NRC IN 2006-01 is comprised of only 16 segments. Both plants have interior and exterior torus diameter support columns at the juncture of the segments. Both tori are approximately the same diameter. Therefore, NMP1's support columns are not as heavily loaded (more columns result in less load).

The plant systems that may inject steam into the torus are the emergency condenser system vent (known as the high point vent), the clean-up system

exhaust, and the electromatic relief valves. The small-bore diameter high point vent is a secondary emergency condenser flow path that may be opened through motor-operated valves (normally closed) which allows for continued venting under post-accident conditions. Venting through this path requires operator action using remote manual control switches and is not used during normal plant operations.

The end of the vent pipe, which includes the exhaust for the clean-up system is under water, is capped and has a sparger allowing for steam condensing. This system configuration would not introduce the event that occurred at the subject BWR station.

The electromatic relief valves inject steam through the safety relief valve (SRV) line into the torus through quenchers. The end of the quencher pipe is under water, is capped and has a sparger allowing for steam condensing. The SRV vent lines do not penetrate the torus shell; they enter the torus through the vent pipes, to the quencher and, therefore, would not subject the torus shell to a similar load as experienced by the subject BWR's torus. This configuration addresses the root cause of the event that occurred at the subject BWR station.

This operating experience example provides objective evidence that industry operating experience is reviewed, evaluated, and actions are taken to ensure that events that have occurred at other stations will not occur at NMP1.

The operating experience relative to the ASME Section XI, Subsection IWE program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of preload, loss of material, loss of sealing, and loss of leak tightness. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Section XI, Subsection IWE program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the ASME Section XI, Subsection IWE program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced ASME Section XI, Subsection IWE program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.30 ASME Section XI, Subsection IWF**Program Description**

The ASME Section XI, Subsection IWF aging management program is an existing condition monitoring program that consists of visual examination of ASME Section XI Class 1, 2, 3, and MC piping and component support members for loss of material, reduction in fracture toughness, loss of mechanical function, cracking, pitting crevice corrosion, overload, wear, dirt and debris accumulation, and loss of preload in air-indoor uncontrolled, air-outdoor, or treated water environments. Bolting for supports is also included with these components and inspected for loss of material and loss of preload by inspecting for missing, detached, or loosened bolts and nuts. The program utilizes procedures that are consistent with industry guidance to ensure proper specification of bolting material, lubricant, and installation torque to prevent or minimize loss of bolting preload or other loss of structural integrity. Indications of degradation are entered in the corrective action program for evaluation or correction to ensure the intended function of the piping and component support is maintained.

The program is implemented through procedures, in accordance with the requirements of ASME Section XI, Subsection IWF, as approved in 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), the ASME Code, Section XI program code of record interval is updated each successive inspection interval (or two consecutive inspection intervals per 10 CFR 50.55a(y), as applicable) to comply with the requirements of the latest edition of the ASME Code specified eighteen months before the start of the inspection interval. The ASME Code edition consistent with the provisions of 10 CFR 50.55a will be used during the subsequent period of extended operation. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation.

The ASME Section XI, Subsection IWF program utilizes inspections that detect degradation before loss of intended function. Preventive measures associated with structural bolts are addressed in implementing procedures.

Support bolting is inspected to identify if there are any loose, missing, cracked or fractured parts, bolting or fasteners during the inspections. The reactor vessel support skirt to ring girder bolting consists of 48 high-strength bolting (A490) in sizes greater than 1-inch nominal diameter. Additionally, six ASME Class 1 and 2 pipe supports also include high-strength bolting (A490) in sizes greater than 1-inch nominal diameter.

The program is enhanced to perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of a 20 percent representative sample of high-strength bolts (defined as bolts with the same material and environment combination), on a 10-year frequency during the subsequent period of extended operation. Volumetric examinations will be performed and evaluated by certified nondestructive examination (NDE) personnel in accordance with Constellation procedures. If the volumetric examination of these bolts reveals conditions that do not meet acceptance criteria, then the results will be entered into the corrective action program and the inspection will be expanded to include additional high-strength bolts. The sample of high strength bolting materials subject to volumetric examination will be comprised of 10 bolts from the drywell

population, six from the reactor building population, and 13 from the turbine building population.

The 20 percent sample size is consistent with other sampling programs. The volumetric examinations will be expanded to include additional high strength bolts if the volumetric examination of a high strength bolt shows adverse results.

Supports within the scope of ASME Section XI, Subsection IWF do not have elastomeric vibration elements at NMP1.

The ASME Section XI Inservice Inspection, Subsection IWF program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are generally applicable to all Constellation plants, with certain aspects limited to operation beyond 60 years. The equivalent ASME Section XI Inservice Inspection, Subsection IWF program for Peach Bottom Atomic Power Station, including the aspects of the program applicable to operation beyond 60 years, has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the ASME Section XI Inservice Inspection, Subsection IWF program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The ASME Section XI, Subsection IWF aging management program will be consistent with the ten elements of aging management program XI.S3, "ASME Section XI, Subsection IWF," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the ASME Section XI, Subsection IWF program will be enhanced to:

1. Perform periodic evaluations of the acceptability of inaccessible areas of supports (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe), when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas of supports. Perform these evaluations once every 10 years during the subsequent period of extended operation. **Program Elements Affected: Scope of Program (Element 1)**
2. Perform a one-time inspection of an additional five percent of the currently inspected sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. The one-time inspection will be conducted within five years prior to entering the subsequent period of extended operation. The additional supports

will be selected from the remaining population of IWF piping supports not already included in the current inspection sample. The expanded sample locations will be selected to include components that are more susceptible to age-related degradation (i.e., based on factors such as time in service, material, and aggressiveness of the environment) than those not in the sample. **Program Elements Affected: Detection of Aging Effects (Element 4)**

3. Revise procedures to require volumetric examination of high-strength bolting (actual measured yield strength greater than or equal to 150 ksi) in sizes greater than 1-inch nominal diameter (including ASTM A490 and equivalent ASTM F2280), if additional high-strength bolting is installed. The examination shall be comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 and performed at least once per 10-year interval to detect cracking, in addition to the VT-3 examination required by ASME Section XI. **Program Elements Affected: Detection of Aging Effects (Element 4)**
4. Provide guidance regarding the selection of supports to be examined in subsequent inspection intervals, when a support that is acceptable for continued service, as defined in IWF-3400, is restored in accordance with the corrective action program. The enhanced guidance will ensure that the successive inspection is increased or modified to include another support, of the same type and function, that has not been restored to correct the observed condition. **Program Elements Affected: Monitoring and Trending (Element 5)**
5. Perform volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of a 20 percent representative sample of high-strength bolts (defined as bolts with the same material and environment combination), on a 10-year frequency during the subsequent period of extended operation. The sample shall include the bolting that is most susceptible to age-related degradation (i.e., based on time in service, aggressive environment). If the volumetric examination of these bolts reveals conditions that do not meet acceptance criteria, then the results will be entered into the corrective action program and the inspection will be expanded to include additional high-strength bolts. **Program Element Affected: Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. One-time inspections will be completed within the five years prior to the subsequent period of extended operation and no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI, Subsection IWF program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an AMP effectiveness review was performed by using Constellation procedural guidance and industry standards. The AMP effectiveness review assessed the key attributes of the existing ASME Section XI, IWF AMP effectiveness, including but not limited to detection of aging effects, corrective

actions, evaluation of industry and plant-specific operating experience informing the AMP, and verifying license renewal commitments are properly maintained. The review concluded that inspections have been performed in accordance with specified commitment implementation activities (e.g., preventive maintenance tasks, walkdowns, inspections). No adverse trends or deficiencies were identified during the inspections or any previous corrective actions. The program was determined to be effectively managing aging in accordance with the existing 10 elements of the AMP.

This operating experience example provides objective evidence of aging management program effectiveness during the first period of extended operation. This example also demonstrates that periodic program effectiveness reviews are performed to ensure that program effectiveness is maintained and to drive continuous improvement.

2. In 2021, a VT-3 examination conducted on an ASME Section XI Class 1 spring hanger revealed that the support load was outside the acceptable tolerance range. The design cold setting for this support was specified at 3,921 pounds, while the field measurement indicated a load of approximately 3,400 pounds.

According to engineering specifications, a tolerance of 10 percent is permitted, resulting in an acceptable range of 3,529 pounds to 4,313 pounds. Historical records show that the as-found load in 2017 was 3,600 pounds, and following a repair in 1988, the as-left load was recorded at 3,650 pounds. Given that the 1988 repair restored the support to service, the 3,650 pounds value should be considered the baseline for trending purposes.

Applying the 10 percent tolerance to the 3,650 pounds baseline yields a lower bound of 3,285 pounds, which encompassed the 2021 as-found value of 3,400 pounds.

Corrective actions were taken to restore the spring support load to the baseline value of 3,650 pounds.

This operating experience example provides objective evidence that IWF pipe support examinations are effective at identifying degraded conditions. When degraded conditions are identified, the conditions are evaluated, corrective actions are taken, and the extent of identified degraded conditions are addressed prior to a loss of intended function.

3. In 2025, non-destructive examination (NDE) services performed a VT-3 visual examination on an ASME Section XI Class 1 constant spring support. The inspection identified that three of four position indicators were outside the 10 percent cold load setting tolerance, and the fourth support lacked a cold load setting mark.

Engineering reviewed the condition and referenced a prior evaluation documented from 2015, which clarified that constant spring supports differ from variable springs. Unlike variable springs that have distinct hot and cold load values, constant springs are designed to maintain a single constant load across the full range of pipe movement due to thermal expansion.

The position indicator should fall between the hot and cold markings on the scale. If outside this range, the condition is rejectable and adjustment is recommended. However, in this case, the spring can was not bottomed out in either direction and remained within total travel limits. Therefore, the support was deemed functionally acceptable.

Two of the four spring cans (positions A and B) appeared to lack thread engagement when viewed through the sight holes. A follow-up walkdown by Site Design Engineering confirmed full thread engagement was present upon closer inspection.

Engineering concurred with NDE's assessment that the current configuration is acceptable. The condition is considered a preexisting setup dating back to the recirculation loop/safe end replacement in the early 1980s.

This operating experience example provides objective evidence that IWF pipe support examinations are effective at identifying degraded conditions. When degraded conditions are identified, conditions are evaluated, corrective actions are taken, and the extent of identified degraded conditions are addressed prior to a loss of intended function.

The operating experience relative to the ASME Section XI, Subsection IWF program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material, reduction in fracture toughness, loss of mechanical function, loss of preload, and cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the ASME Section XI, Subsection IWF program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the ASME Section XI, Subsection IWF program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced ASME Section XI, Subsection IWF program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.31 10 CFR Part 50, Appendix J**Program Description**

The 10 CFR Part 50, Appendix J aging management program is an existing performance monitoring program that consists of monitoring and determining leakage rates through the containment system as a whole including the shell, 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.

The 10 CFR Part 50, Appendix J aging management program manages the loss of material, loss of leak tightness, cracking, and loss of bolting preload in the containment and various systems penetrating primary containment. The program also detects loss of sealing due to degradation of elastomer gaskets and seals. The program manages steel and stainless steel containment elements, penetration sleeves, hatches, manways, airlocks, and bolting in air-indoor uncontrolled and treated water environments.

This program complies with Option B requirements of 10 CFR Appendix J with plant-specific exceptions approved by the NRC as part of license amendments, and implements the guidelines provided in 10 CFR 50, Appendix J Option B; Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program;" NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J;" ANSI/ANS 56.8, "Containment System Leakage Testing Requirements;" and Bechtel Topical Report BN-TOP-1, "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants."

Containment leak rate tests are performed using station procedures to ensure that leakage through the containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B and the station Primary Containment Leakage Rate Testing Program. Local leak rate tests (LLRT) are performed on primary containment isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR 50, Appendix J, Option B and the station Primary Containment Leakage Rate Testing Program. Principal penetrations and components required to be leak rate tested are identified in UFSAR Tables VI-1, VI-2, VI-3a, and VI-3b. Components excluded from testing are identified in various engineering change documents. The aging management programs that manage the aging effects associated with components excluded from leak rate testing include the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program, External Surfaces Monitoring of Mechanical Components (B.2.1.23) program, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24) program, One-Time Inspection (B.2.1.20) program, Selective Leaching (B.2.1.21) program, TLAA, and Water Chemistry (B.2.1.2) program. General visual inspection of the accessible interior and exterior surfaces of the containment structures and components, including the penetrations, are performed per the ASME Section XI, Subsection IWE (B.2.1.29) program.

Monitoring and trending is performed by comparing valve and penetration leakage from test results to administrative leakage limits that are set lower than the regulatory acceptance criteria. The Primary Containment Leak Rate Testing Program demonstrates that the test results meet the acceptance criteria. Evaluations are performed for test or inspection results that do not satisfy established criteria and an entry into the corrective action program (CAP) is initiated to document the issue in accordance with station procedures.

The 10 CFR Part 50, Appendix J aging management program utilizes periodic testing and inspections that effectively detect degradation before loss of intended function. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation.

The program provides reasonable assurance that the aging effects addressed by this aging management program will be adequately managed during the subsequent period of extended operation.

NUREG-2191 Consistency

The 10 CFR Part 50, Appendix J aging management program is consistent with the ten elements of aging management program XI.S4, “10 CFR Part 50, Appendix J,” specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the 10 CFR Part 50, Appendix J program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. An aging management program effectiveness review was performed on the NMP1 Appendix J Program in September 2025. The purpose of the review was to verify that aging effects are being detected and addressed prior to loss of intended function. Four objectives were addressed: detection of aging effects, corrective action program usage, operating experience benchmarking, and license renewal commitment management. It was determined that the program is effectively managing aging effects of in scope SSCs to ensure the loss of function does not occur. No issue reports were generated as a result of this review.

This operating experience example provides objective evidence that the 10 CFR Part 50, Appendix J program is periodically assessed to identify key learnings that support continuous improvement.

2. A Focused Area Self-Assessment (FASA) for the Constellation fleet Appendix J program was conducted in 2016. NMP1 was evaluated as part of this assessment. The purpose of the FASA was to evaluate the fleet Appendix J Primary Containment Leak Rate Testing program and to confirm the current practices utilize or provide the basis for improvement in the specific site programs. The FASA concluded that the objectives reviewed relative to NMP1 were met successfully. The assessment report highlighted that NMP1 test frequencies are being set appropriately, the CAP process is being utilized correctly, and the maximum path and minimum path leakage calculations are being performed correctly. The results of this FASA were distributed to Constellation site Appendix J managers, engineering programs managers, and site engineering directors. This assessment provides evidence that NMP1 Appendix J program maintains procedural compliance.

This operating experience example provides objective evidence that the 10 CFR Part 50, Appendix J program is periodically assessed to identify key learnings that support continuous improvement.

3. The most recent ILRT performed at NMP1 was in spring 2023. The adjusted as-left leakage rate was within acceptance criteria. The result was below the maximum limit allowed by the Technical Specifications. All Type A test criteria were met during this ILRT. These results show that in scope components that make up the primary containment boundary are being adequately maintained, and that safety margin is maintained between the Technical Specifications allowable limits and the as-tested values.

This operating example provides objective evidence that the 10 CFR Part 50, Appendix J program effectively manages leakage from the primary containment, and systems and components that penetrate primary containment which ensures that the measured leakage does not exceed allowable leakage rate values as specified in the Technical Specifications and associated bases.

4. NRC Information Notice 92-20 was issued to alert licensees to problems with local leak rate testing of two-ply stainless steel (SS) bellows used on pipe penetrations, failure to consider gasketed flanges as leakage paths, and water seal adequacy related to post-accident containment boundaries. These concerns were raised with OE from other sites. NMP1 responded with a self-assessment of the impacted areas and demonstration of compliance with each concern.

This operating experience example provides objective evidence that station operating experience is being reviewed and evaluated to confirm that station testing procedures are effective in maintaining containment integrity.

The operating experience relative to the 10 CFR Part 50, Appendix J program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the 10 CFR Part 50, Appendix J program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific

and industry operating experience. Therefore, there is confidence that continued implementation of the 10 CFR Part 50, Appendix J program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing 10 CFR Part 50, Appendix J program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.32 Masonry Walls

Program Description

Masonry Walls is an existing condition monitoring aging management program based upon NRC IE Bulletin (IEB) 80-11, "Masonry Wall Design," and NRC Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11."

The responses to NRC IEB 80-11 include, (a) the identification of safety-related masonry walls in close proximity to or having attachments from safety-related systems or components, and (b) the evaluation of the design adequacy and construction details used for the safety-related masonry walls.

The responses to NRC IN 87-67 documented that the evaluation bases developed in response to NRC IEB 80-11 were not invalidated by (a) deterioration of the masonry walls (e.g., new cracks not considered in the reevaluation), (b) physical plant changes such as installation of new safety-related systems or components in close proximity to masonry walls, or (c) reclassification of systems or components from nonsafety-related to safety-related, provided appropriate evaluation is performed to account for such occurrences. The responses to NRC IN 87-67 also documented the administrative controls to ensure that the evaluation bases developed in response to NRC IEB 80-11 remain valid.

Steel edge supports and steel bracings are part of the masonry wall design and are considered as component supports and aging effects are managed by the Structures Monitoring (B.2.1.33) program.

The scope of the Masonry Walls program includes safety-related masonry walls in indoor air, uncontrolled environments determined to be within the scope of the Maintenance Rule as a result of the response to NRC IEB 80-11, and nonsafety-related masonry walls in structures in the scope of license renewal.

The masonry walls will be monitored under the enhanced Structures Monitoring (B.2.1.33) program through periodic visual inspection at an interval of not greater than five years to ensure that a loss of intended function does not occur. The objective of the Masonry Walls program is to manage the aging effects of loss of material, loss of bond, and cracking of masonry units and mortar. Conditions found to be "acceptable with deficiencies" or deemed to be "unacceptable" are documented and entered into the corrective action program for evaluation which will result in further analysis, repair or replacement, as necessary.

The Masonry Walls aging management program utilizes periodic inspections that effectively detect degradation before loss of intended function. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation.

The Masonry Walls program is implemented by the Structures Monitoring (B.2.1.33) program, which was developed to satisfy the requirements of 10 CFR 50.65, the Maintenance Rule. Masonry walls that are designated as fire barriers are also inspected and managed within the Fire Protection (B.2.1.15) program.

The program will provide reasonable assurance that the aging effects addressed by the Masonry Walls aging management program will be adequately managed during the subsequent period of extended operation.

NUREG-2191 Consistency

The Masonry Walls aging management program will be consistent with the ten elements of aging management program XI.S5, "Masonry Walls," specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

1. NUREG-2191, AMP XI.S5 states that in general, all structures are monitored on an interval not to exceed five years. The normally inaccessible areas due to high radiation, including the main steam tunnel, heater bays, and the condenser bays, will be inspected on an interval not to exceed every third refueling outage.

Program Element Affected: Detection of Aging Effects (Element 4)

Justification for Exception

The inspection frequency for the normally accessible areas is being enhanced to bring the frequency from every third refueling outage which is typically around six years to a five-year frequency while the normally inaccessible areas inspection frequency will remain at an interval not to exceed every third refueling outage. Inspections of the normally accessible areas would give indications for the normally inaccessible areas. The existing inspection frequency of every third refueling outage has demonstrated the effectiveness of managing the applicable aging effects for the structures within the scope of this program. Visual inspections have ensured that aging degradation has been detected and evaluated before a loss of a structure's intended function. In addition, the exception would not preclude more frequent inspections if more frequent inspections were deemed necessary. A similar approach was previously approved by the NRC as documented in the Safety Evaluation Related to the Subsequent License Renewal of Monticello Nuclear Generating Plant, Unit 1 (ADAMS Accession No. ML24077A001).

Enhancements

In the elements identified below, the Masonry Walls aging management program will be enhanced to:

1. Perform masonry wall periodic inspections on a frequency not to exceed five years except for the normally inaccessible areas due to high radiation. **Program Element Affected: Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Masonry Walls program will be effective in ensuring that intended functions are

maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an assessment of the effectiveness of the Masonry Walls aging management program was performed. The assessment determined that the program was effective in managing the aging effects of in scope masonry walls to ensure a loss of function does not occur. The Masonry Walls program is implemented through the Structures Monitoring aging management program. A review of the inspection criteria in the Structures Monitoring inspection checklist found all required and some additional inspection attributes are included. The review documents the inspection frequency of reinforced masonry walls in good condition as being performed every six years and unreinforced masonry walls in good condition are inspected no more than every four years. The assessment performed a gap analysis of NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 2 to determine if changes in the revision should be implemented. The analysis determined that there were no significant changes between the revisions, therefore the existing program was not impacted. Reviews were also performed to determine if any industry, fleet, or site-specific operating experience was applicable to the program. No relevant operating experience was identified that provided potential enhancements to the Masonry Walls aging management program.

This example shows objective evidence that periodic assessments of the Masonry Walls aging management program are performed to identify and improve program elements to maintain program effectiveness.

2. In 2009, during a Structures Monitoring walkdown, four threaded rods with square washer plates were found deformed inward into masonry wall 23. The concrete masonry units were chipped around the threaded rods. Engineering determined the threaded rods supported a retired in-place electrical enclosure on the opposite side of the wall. The location and extent were documented via pictures and a written description. The issue was entered into the corrective action program. Engineering reviewed the design calculations for the masonry wall and determined the condition did not affect the structural integrity of the wall and did not prevent the wall from performing its design function. Subsequent Structures Monitoring walkdowns in 2013, 2017 and 2021 did not identify any new degradation or structural integrity concerns in the masonry wall.

This example demonstrates that deficiencies are entered into the corrective action program and appropriate corrective actions are taken to evaluate and monitor deficiencies.

3. In 2015, during an NRC walkdown, a small crack following the mortar line of masonry wall 27 near a penetration was identified. Structural engineering performed a follow-up walkdown of the wall. The calculation of the wall was reviewed, similar cracking identified in discussions of the calculation indicate that the crack had an insignificant effect on the wall's structural integrity and did not prevent the wall from performing its design function. The issue was entered into the corrective action program. Subsequent Structures Monitoring walkdowns have not shown additional deterioration of the masonry wall.

This example demonstrates that deficiencies are entered into the corrective action program and appropriate corrective actions are taken to evaluate and monitor deficiencies.

The operating experience relative to the Masonry Walls program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including shrinkage, separation, gaps, loss of material, and cracking of masonry walls. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Masonry Walls program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Masonry Walls program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Masonry Walls program will provide reasonable assurance that the identified shrinkage, separation, gaps, loss of material, and cracking aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.33 Structures Monitoring

Program Description

The Structures Monitoring aging management program is an existing condition monitoring program that consists of periodic visual inspection and monitoring of the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those describe in ACI 349.3R-02, ACI 201.1R, SEI/ASCE 11, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of the degradation. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program will include personnel qualifications and quantitative evaluation criteria of ACI 349.3R. Inspection frequency for the in scope structures will not exceed five years, with provisions for more frequent inspections when conditions are observed that have a potential for impacting an intended function. Unacceptable conditions, when found, are evaluated or corrected in accordance with the corrective action program. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to detect significant age-related degradation prior to loss of intended function.

The Structures Monitoring aging management program was developed to implement the requirements of 10 CFR 50.65 and is based on NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program includes elements of the Masonry Walls (B.2.1.32) program and Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34) program.

Concrete structures are inspected for indications of deterioration and distress including evidence of leaching, loss of material, cracking, and a loss of bond, as defined in ACI 201.1R. Steel components are inspected for loss of material due to corrosion.

Inspections also include steel edge supports and steel bracings associated with masonry walls. Inspections will also be performed for seismic joint fillers and elastomeric materials used in structural applications.

The program also includes provisions for periodic testing and assessment of groundwater chemistry and opportunistic inspections of accessible below grade concrete structures.

Protective coatings are not relied upon to manage the effects of aging for structures included in the scope of this program. A de-watering system is not relied upon to control settlement and porous concrete was not used in the design of foundations.

Applicable components within the scope of this program include, but are not limited to: bolting, concrete anchors and embedments, concrete components, precast concrete, expansion joints, siding, doors, duct banks, foundations, plugs, hatches, missile barriers, metal components such as vents and louvers, miscellaneous steel,

penetration seals and sleeves, pipe whip restraints and jet impingement shields, steel components, steel liners, supports, racks, panels, cabinets, enclosures, cable trays, sliding surfaces, roofing, conduit, and tube track.

Applicable metallic materials within the scope of this program include aluminum, carbon steel, galvanized steel, lubrite, and stainless steel. Applicable bolting materials within the scope of this program include carbon steel, galvanized steel, and stainless steel. Applicable non-metallic materials within the scope of this program include concrete, elastomers, and grout.

Applicable environments for components within the scope of this program include air-indoor uncontrolled, air-outdoor, groundwater and soil, raw water, treated water, and water-flowing.

Applicable aging effects managed by this program include cracking, distortion, increase in porosity and permeability, loss of bond, loss of material, loss of mechanical function, loss of mechanical properties, loss of preload, loss of sealing, loss of strength, reduction in concrete anchor capacity, and reduction or loss of isolation function.

NUREG-2191 Consistency

The Structures Monitoring aging management program will be consistent with the ten elements of aging management program XI.S6, "Structures Monitoring," specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. An exception to the inspection of inaccessible area frequency will be taken. NUREG-2191, AMP XI.S6 states that in general, all structures are monitored on an interval not to exceed five years. The inspection frequency for normally inaccessible areas due to high radiation, including primary containment, main steam tunnel, heater bays, and the condenser bays, may exceed five years as they will be inspected on an interval not to exceed every third refueling outage.
Program Element Affected: Detection of Aging Effects (Element 4)

Justification for Exception

The inspection frequency for the normally accessible areas is being enhanced to bring the frequency from every third refueling outage, which is typically around six years to a five year frequency while the normally inaccessible areas inspection frequency will remain at an interval not to exceed every third refueling outage. Inspections of the normally accessible areas would give indications for the normally inaccessible areas. The existing inspection frequency of every third refueling outage has demonstrated the effectiveness of managing the applicable aging effects for the structures within the scope of this program. Visual inspections have ensured that aging degradation has been detected and evaluated before a loss of a structure's intended function. In addition, the exception would not preclude more frequent inspections if more frequent inspections were deemed necessary. A similar approach was previously approved by the NRC as documented in the Safety Evaluation Related to the

Subsequent License Renewal of Monticello Nuclear Generating Plant, Unit 1
(ADAMS Accession No. ML24077A001).

Enhancements

In the elements identified below, the Structures Monitoring aging management program will be enhanced to:

1. Include the following structures within the scope of the program:
 - a. Administration building (Original)
 - b. Administration building extension
 - c. Emergency diesel generator fuel oil storage tank foundation
 - d. Emergency diesel generator fuel oil transfer valve pit
 - e. Ring girder for the reactor vessel support skirt

Program Elements Affected: Scope of Program (Element 1)

2. Include the following components and commodities within the scope of the program:
 - a. Manholes
 - b. Seismic joint filler
 - c. Sliding surfaces
 - d. Trash racks

Program Elements Affected: Scope of Program (Element 1)

3. Implement preventive actions to emphasize proper selection of bolting material and lubricants and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high strength bolting. For ASTM A325 or ASTM A490 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection will be in accordance with Section 2 of Research Council for Structural Connection publication "Specification for Structural Joints Using High-Strength Bolts." **Program Element Affected: Preventive Actions (Element 2)**
4. Clarify procedures to state that evidence of cracking, spalling, scaling, discoloration, and leaching could indicate the presence of increased porosity and permeability due to mechanisms of aggressive chemical attack or leaching of calcium hydroxide and carbonation. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**
5. Expand the program to monitor accessible sliding surfaces for indications of significant loss of material due to wear or corrosion and for accumulation of debris or dirt. Establish acceptance criteria for sliding surfaces as no significant

loss of material due to wear or corrosion and no debris or dirt that could restrict or prevent sliding of the surfaces, as required by design. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Acceptance Criteria (Element 6)**

6. Expand the program to monitor elastomeric structural sealants, seismic joint fillers, and vibration isolators for cracking, loss of material, and hardening. Supplement visual inspection of elastomeric elements with tactile inspection to detect hardening if the intended function is suspect. Establish acceptance criteria for elastomeric structural sealants, seismic joint fillers, and vibration isolation elements as no loss of material, cracking, or hardening that can lead to loss of intended function. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)**
7. Develop a new implementing procedure or revise an existing implementing procedure to address aging management of inaccessible areas exposed to potentially aggressive groundwater/soil environment that will include the following:
 - a. Monitor raw water and ground water chemistry for pH, chlorides, and sulfates, on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year), from locations that are representative of the groundwater in contact with structures within the scope of subsequent license renewal.
 - b. Develop engineering evaluations to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or increased frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil.
 - c. Develop the initial engineering evaluations prior to the subsequent period of extended operation. Develop follow-up engineering evaluations on an interval not to exceed five years.
 - d. If warranted based on the engineering evaluations, perform focused inspections of representative, accessible (leading indicator) structural elements, or if accessible areas will not be leading indicators for the potential aging mechanisms, excavate and inspect buried concrete elements exposed to potentially aggressive groundwater/soil.
 - e. If degraded concrete is identified, as part of the focused inspections of leading indicators (representative, accessible or exposed inaccessible concrete), enter adverse results that exceed ACI 349.3R-02 tier 2 criteria into the corrective action program, and expose inaccessible concrete so that the extent of the condition can be determined, baseline conditions documented,

and additional actions identified such as repairs, new preventive actions, additional evaluations, and future inspections.

Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

8. Monitor and trend indications of groundwater infiltration or through-concrete leakage. If leakage volumes allow, procedures will be revised to clarify that water chemistry analysis should be considered for parameters including pH, as well as mineral, chloride, sulfate and iron content in the water to assess for potential impact on age-related degradation of concrete or steel reinforcement. This assessment may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. **Program Elements Affected: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)**
9. Perform structures monitoring periodic inspections on a frequency not to exceed five years except for the normally inaccessible areas due to high radiation. **Program Element Affected: Detection of Aging Effects (Element 4)**
10. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R-02 with respect to knowledge of inservice inspection of concrete and visual acuity requirements. **Program Element Affected: Detection of Aging Effects (Element 4)**
11. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. **Program Element Affected: Detection of Aging Effects (Element 4)**
12. Provide additional guidance on visual indications such as exudations, surface staining, expansion causing structural deformation, relative movement or displacement, misalignment or distortion of attached components for detection of expansion due to alkali-aggregate reactivity in concrete. **Program Element Affected: Detection of Aging Effects (Element 4)**
13. Quantitative baseline inspection data will be established against acceptance criteria provided in the enhanced Structures Monitoring program prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria are acceptable in lieu of performing a new baseline inspection. **Program Element Affected: Monitoring and Trending (Element 5)**
14. Provide evaluation criteria for structural concrete by using quantitative second tier criteria in Chapter 5 of ACI 349.3R-02. **Program Element Affected: Acceptance Criteria (Element 6)**
15. Clarify that loose bolts and nuts are not acceptable unless accepted by engineering evaluations. **Program Element Affected: Acceptance Criteria (Element 6)**

The program will be enhanced and the initial engineering evaluation will be completed no later than six months prior to the subsequent period of extended operation. Baseline inspections will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Structures Monitoring program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, a program effectiveness review was performed on the Structures Monitoring program. This review included verification that commitments are being implemented and any commitment changes are performed in accordance with approved processes; aging effects are being effectively managed such that intended functions are maintained; and internal and external operating experience is effectively used. The review also included verification that first license renewal enhancements were included in the Structures Monitoring program.

The effectiveness review concluded that the Structures Monitoring program is being implemented in accordance with site and corporate Structures Monitoring procedures. A review of issue reports determined that the corrective action program is being utilized to maintain the effectiveness of the Structures Monitoring program. A review of site, fleet, and industry experience did not identify any enhancements necessary for the program. The review confirmed that all recurring preventive maintenance activities have been completed in accordance with program schedule requirements as per the site Structures Monitoring program procedure.

This operating experience example provides objective evidence that the Structures Monitoring program effectively monitors and manages the condition of components and structures. This example also demonstrates that periodic program effectiveness reviews are performed to ensure that program effectiveness is maintained and to drive continuous improvement.

2. In 2021, during the performance of the Structures Monitoring program inspections for the turbine building, cracking and spalling was found on a column within the main steam tunnel. The condition found was dispositioned to be acceptable with deficiencies. As a result from this inspection, the columns will be inspected every outage (when the location is accessible) as part of the Structures Monitoring program for trending purposes and further evaluation as necessary.

This operating experience example provides objective evidence that the Structures Monitoring program will increase the frequency of certain areas of the plant, as needed, in accordance with Structures Monitoring procedures where the program includes provisions for more frequent inspections based on an evaluation of the observed degradation.

3. In 2013, during performance of the Structures Monitoring program inspections for the area below 256' of the screen and pump house, the inspector observed water infiltration was occurring through a penetration which is north of the service water pumps. This penetration was previously repaired, and water was still infiltrating. Therefore, an issue report was entered into the corrective action program to fully repair the penetration via externally digging and then filling in the penetration completely. This work was completed in 2015.

During the 2015 and 2021 performances of the Structures Monitoring program inspections for the area below 256' of the screen and pump house, the inspector observed that the penetration north of the service water pumps, that was previously known to have water infiltration, had no signs of water infiltration since the repair done in 2015.

This operating experience example provides objective evidence that the Structures Monitoring program enters deficiencies into the corrective action program and corrective actions are taken to correct degraded conditions. This also provides evidence that previous repairs and corrective measures are monitored to ensure that they fix the issue and that if the issue has not been fixed, more thorough repairs are done to ensure that the issue has been resolved.

4. The inspection of roofs is included within the scope of the Structures Monitoring program. Inspection activities, including minor repair activities, are performed by maintenance personnel.

An example of the inspection is an occurrence in 2017 when two small holes and one split on the Unit 1 reactor building roof were observed. The roof was immediately fixed, and additional caulk was added on open seams in expansion joint flashing. Also, during this inspection, previously observed roof leaks that were captured in the corrective action program were repaired, such as a roof leak in the northeast corner of the Unit 1 turbine building roof.

This operating experience provides objective evidence that the conditions are evaluated and promptly repaired to ensure the intended function of the roofs are maintained.

5. In 2009, an ANI letter of recommendation stated that engineering should perform a periodic walk down of the accessible portions of the spent fuel pool to inspect for through-wall leakage. In addition to this recommendation, there is site operating experience of leakage from the spent fuel pool where a flaw in the liner was discovered in 1990 and repaired in 1992. From this data, a recurring engineering inspection was established to inspect the accessible exterior walls to the spent fuel pool to identify indications of through-wall leakage. This scheduled walkdown inspection has a typical inspection frequency of two years and was last completed in 2025 and 2023. This recurring engineering inspection is in addition to the Structures Monitoring program inspection which also is responsible for structures in the area. From these additional walkdowns and structures monitoring walkdowns, structural conditions have been assessed and compared to previous inspection results. No significant adverse conditions or through-wall leakage has been discovered.

This operating experience provides objective evidence that industry recommendations are evaluated in conjunction with station operating experience to identify and respond to potential deficiencies.

The operating experience relative to the Structures Monitoring program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, increase in porosity and permeability, loss of bond, loss of material, loss of sealing, loss of strength, reduction in concrete anchor capacity, and reduction of strength. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Structures Monitoring program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Structures Monitoring program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Structures Monitoring program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants**Program Description**

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program is an existing condition monitoring program that consists of inspection and surveillance of water-control structures that are in scope for license renewal. These structures consist of the screenhouse, the intake tunnel (including the lakeside intake structure), and the discharge tunnel (including the lakeside discharge structure).

Structural components and commodities monitored under this program include steel bolting, concrete anchors and curbs; reinforced concrete members such as interior and exterior walls, slabs, beams, panels, columns, foundations and sub-foundations, the trash rack, equipment supports and foundations, structural steel and hatches/plugs.

The program manages loss of material, cracking, loss of bond, increase in porosity and permeability, loss of strength, and loss of form. Environments include air-indoor uncontrolled, air-outdoor, raw water, and water flowing.

The program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect the intended functions of the water-control structures and components in the scope of this program. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent the loss of intended function due to significant age-related degradation. Elements of the program are designed to provide records of periodic inspections and evaluations of structural conditions to detect age-related deterioration and degradation and to initiate maintenance activities and corrective actions so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner.

In general, parameters monitored are in accordance with Section C.2 of NRC Regulatory Guide (RG) 1.127, "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. Nine Mile Point Nuclear Station, Unit 1 is not currently committed to the requirements in NRC RG 1.127 but has been implementing the guidance of NRC RG 1.127 for the structures in scope for license renewal through station procedures, work orders, and inspections. The aging management program is based on the guidance provided in NRC RG 1.127 and ACI 349.3R-02. Structures exposed to aggressive raw water and ground water require additional plant-specific investigation.

Structures located underwater will not be accessible for evaluation with the same level of visual acuity as structures above water. Inspections will be implemented that establish the condition of these structures by using divers, remotely operated vehicles, an equivalent inspection method to divers, or by dewatering, as well as by considering the conditions of the exposed portions of the structures, at the waterline and above, which can serve as an indicator of conditions underwater. These measures allow for the characterization of long-term aging effects to a level of detail

that can be used to determine whether additional inspection measures are warranted, and to prioritize any further inspection or evaluation efforts so that this aging management program will be effective in assuring that intended functions of submerged structures are maintained consistent with the current licensing basis for the subsequent period of extended operation.

Inspections will be performed at least once every five years for structural components except for the intake tunnel and discharge tunnel which will be inspected on an interval not to exceed every third refueling outage. The inspection activities include cleaning of areas covered by silt, vegetation, or marine growth to allow for inspections. The raw water at NMP1 is not considered to be aggressive based on chemistry records that indicate pH, sulfates, and chlorides are below the threshold limits to be considered aggressive.

The NMP1 design does not include dams, embankments, reservoirs, slopes, canals or flood protection in scope for subsequent license renewal.

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program is implemented through the Structures Monitoring (B.2.1.33) program for the associated in scope structures.

NUREG-2191 Consistency

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be consistent with the ten elements of aging management program XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," specified in NUREG-2191 with the following exception:

Exceptions to NUREG-2191

1. NUREG-2191, AMP XI.S7 states periodic inspections are to be performed at least once every five years. The intake tunnel and discharge tunnel will be inspected on an interval not to exceed every third refueling outage. **Program Element Affected: Detection of Aging Effects (Element 4)**

Justification for Exception

The intake tunnel and discharge tunnel are submerged in non-aggressive raw water and was last inspected in 2013 with no structural integrity concerns noted in the inspection. The inspection frequency of the intake tunnel and discharge tunnel will be on an interval not to exceed every third refueling outage. The inspection of the other submerged areas (forebay and secondary forebay) of the Screen and Pump House Building will be enhanced to be inspected within the recommended five-year frequency. The forebay of the screenhouse is exposed to similar conditions to the intake tunnel and the discharge tunnel and, therefore the results of the aforementioned inspection will be an indicator of the condition of the intake tunnel and discharge tunnel. The raw water exposed to submerged structures of the Screen and Pump House Building has been shown to be non-aggressive. Based upon the exposure to non-aggressive raw water and the inspection of the forebay as an indicator, inspecting the intake tunnel and the discharge tunnel on an interval not to exceed every third refueling outage provides reasonable assurance that the tunnels will perform their intended

function during the subsequent period of extended operation. A similar exception was previously reviewed and approved by the NRC as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Dresden Nuclear Power Station, Units 2 and 3 (ADAMS Accession No. ML25251A150).

Enhancements

In the elements identified below, the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be enhanced to:

1. Add the following structures to the scope of the program:
 - a. Unit 1 Rock Dike
 - b. Unit 2 Revetment-Ditch System (260 ft which replaced Unit 1 Rock Dike)

Program Element Affected: Scope of Program (Element 1)

2. Explicitly include the following components within the scope of the program:
 - a. Trash racks
 - b. Sluice gates

Program Element Affected: Scope of Program (Element 1)

3. Implement preventive actions to emphasize proper selection of bolting materials and lubricants and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For ASTM A325 and ASTM A490 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection will be in accordance with Section 2 of Research Council for Structural Connection publication "Specification for Structural Joints Using High-Strength Bolts." **Program Element Affected: Preventative Actions (Element 2)**

4. Perform periodic inspections of water-control structures on an interval not to exceed five years except for the intake tunnel and discharge tunnel. **Program Element Affected: Detection of Aging Effects (Element 4)**

5. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R-02 with respect to knowledge of inservice inspection of concrete and visual acuity requirements. **Program Element Affected: Detection of Aging Effects (Element 4)**

6. Develop a new implementing procedure or revise an existing implementing procedure to address aging management of inaccessible areas exposed to potentially aggressive groundwater/soil environment that will include the following:

- a. Monitor raw water and ground water chemistry for pH, chlorides, and sulfates on a frequency not to exceed five years that accounts for seasonal variations (e.g., quarterly monitoring every fifth year) from locations that are

representative of the groundwater in contact with structures within the scope of subsequent license renewal.

- b. Develop engineering evaluations to evaluate the water chemistry results to assess the impact, if any, on below-grade concrete, including the potential for further degradation due to the aggressive groundwater, as well as consideration of current conditions. As part of the engineering evaluations, determine if additional actions are warranted, which might include enhanced inspection techniques and/or increased frequency, destructive testing, and focused inspections of representative accessible (leading indicator) or below grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil.
- c. Develop the initial engineering evaluations prior to the subsequent period of extended operation. Develop follow-up engineering evaluations on an interval not to exceed five years.
- d. If warranted based on the engineering evaluations, perform focused inspections of representative, accessible (leading indicator) structural elements, or if accessible areas will not be leading indicators for the potential aging mechanisms, excavate and inspect buried concrete elements exposed to potentially aggressive groundwater/soil.
- e. If degraded concrete is identified, as part of the focused inspections of leading indicators (representative, accessible or exposed inaccessible concrete), enter adverse results that exceed ACI 349.3R-02 tier 2 criteria into the corrective action program, and expose inaccessible concrete so that the extent of the condition can be determined, baseline conditions documented, and additional actions identified such as repairs, new preventive actions, additional evaluations, and future inspections.

Program Element Affected: Detection of Aging Effects (Element 4)

- 7. Quantitative baseline inspection data will be established against acceptance criteria provided in the enhanced Inspection of Water-Control Structures Associated with Nuclear Power Plants program prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria are acceptable in lieu of performing a new baseline inspection. **Program Element Affected: Monitoring and Trending (Element 5)**
- 8. Monitor and trend indications of groundwater infiltration or through-concrete leakage. If leakage volumes allow, procedures will be revised to clarify that water chemistry analysis should be considered for parameters including pH, as well as mineral, chloride, sulfate and iron content in the water to assess for potential impact on age-related degradation of concrete or steel reinforcement. This assessment may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. **Program Element Affected: Detection of Aging Effects (Element 4)**

9. Evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. **Program Element Affected: Detection of Aging Effects (Element 4)**
10. Provide evaluation criteria for structural concrete using quantitative second tier criteria in Chapter 5 of ACI 349.3R-02. **Program Element Affected: Acceptance Criteria (Element 6)**
11. Clarify that loose bolts and nuts are not acceptable unless accepted by engineering evaluations. **Program Element Affected: Acceptance Criteria (Element 6)**

The program will be enhanced and the initial engineering evaluation will be completed no later than six months prior to the subsequent period of extended operation. Baseline inspections will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Inspection of Water-Control Structures Associated with Nuclear Power Plants program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed. The scope of the review included the Structures Monitoring Program which manages the structures in scope of the Inspection of Water-Control Structures Associated with Nuclear Power Plants program. The effectiveness review included a review of completed implementing activities to confirm that applicable aging effects are being detected. Reviews were also performed to determine if any industry, fleet, or station operating experience was applicable to the program. Operating experience (OE) documenting alkali-silica reaction (ASR) found in various seismic category one structures was reviewed. As a result, lessons learned from the OE were incorporated into the Structural Monitoring Program to include the inspection of concrete structures for potential ASR. It is also noted that all the enhancements and recommendations found in the gap analysis of the NUREG 1801, Revision 2 were implemented into the program.

This example shows objective evidence that periodic assessments of the Structures Monitoring aging management program which manage the structures in scope of the Inspection of Water-Control Structures Associated with Nuclear Power Plants program are performed to identify and improve program elements to maintain program effectiveness.

2. Plant operating experience was reviewed to identify instances in which cracks in concrete of water-control structures were identified, the conditions were documented in the corrective action program, and the conditions evaluated. Cracks in concrete are addressed through inspections and corrective actions, and when the cracks are minor, continued monitoring is used to ensure that the

effects of the cracks remain insignificant. Examples of concrete inspections are as follows.

The inspection of the screen and pump house are included within the scope of this program. The inspection of these structures was performed as part of the Structures Monitoring aging management program. These above-water inspections have included steel and concrete elements. The concrete inspections have included the identification of concrete degradation and evaluation of the condition. The review of past Structures Monitoring inspection reports found that in general only minor degradation, such as concrete cracking, steel corrosion, and water leaks, were identified. Age-related issues were evaluated and corrected under the corrective action program resulting in effective implementation of this aging management program. No significant differences in concrete conditions have been identified at the waterline, which could be considered as a leading indicator of underwater conditions.

In 2007, 2009, and 2012, seasonal groundwater leakage through a penetration in the screen and pump house was identified. The cause of this leakage was attributed to higher groundwater levels in the spring and perimeter sump pumps not being operational. Work orders were created from the corrective actions to repair the perimeter sump pumps. The perimeter sump pumps were replaced, and the leakage ceased. Subsequent Structures Monitoring walkdowns of the area have shown no evidence of new groundwater leakage.

In 2003, significant water infiltration was found in the screen and pump house around a retired conduit box at the 233' elevation leading to the corrosion of structural steel members. An issue report was initiated, and a work order was generated to repair the wall. The original repair failed, and an additional issue report was generated in 2014 to pursue a better repair method. The work was performed in 2015, and no leakage has since been documented.

This operating experience example provides objective evidence that concrete structures are inspected, and degradation identified. The conditions are evaluated to determine the cause, impact on required functions, and corrective actions taken to ensure long term integrity, such as repairs or increased monitoring. In addition, industry operating experience is used to inform the concrete inspections.

3. The inspection of the screen and pump house structures include submerged portions using remotely operated vehicles (ROVs) and divers. Examples of the results of these inspections are as follows.

In 2013, an underwater contractor performed a ROV inspection of the intake and discharge tunnels. Engineering reviewed the inspection videos and did not identify any structural concerns. Unremarkable miscellaneous debris was found but was determined not to have an impact to plant operation. During the review lengths of retired conduit on the bottom of the discharge tunnel were found to be mainly covered by sediment. The amount of sediment was found to be insignificant and would have no effect on plant operation. As a result of the inspection, both concrete and steel exposed to raw water were found to be acceptable. The inspections were documented in the corrective action program and in the Structures Monitoring report.

In 2018, divers were performing a modification to remove the bar racks from the intake tunnel inlet structure in order to reduce risk from frazil ice. The diving activities were recorded and reviewed by structural engineering and was found to be in acceptable condition.

Diver inspections of the forebay and the traveling screens have been performed to support plant operation and are cleaned as necessary. For example, in 2017 the circulating water structure and traveling screens were found to be in good condition.

This operating experience example provides objective evidence that the inspections of submerged portions of the structures in the scope of this program are performed, the inspections are adequate to identify degradation, and corrective actions are taken to provide reasonable assurance that aging effects will be addressed prior to a loss of intended function.

The operating experience relative to the Inspection of Water-Control Structures Associated with Nuclear Power Plants program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking, loss of material, loss of bond, increase in porosity and permeability loss of strength and loss of form. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Inspection of Water-Control Structures Associated with Nuclear Power Plants program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Inspection of Water-Control Structures Associated with Nuclear Power Plants program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Inspection of Water-Control Structures Associated with Nuclear Power Plants program will provide reasonable assurance that the identified cracking, loss of material, loss of bond, increase in porosity and permeability loss of strength and loss of form aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.35 Protective Coating Monitoring and Maintenance

Program Description

The Protective Coating Monitoring and Maintenance aging management program provides for aging management of Service Level I coatings inside the primary containment as defined in Regulatory Guide (RG) 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.” The failure of the Service Level I coatings could adversely affect the operation of the emergency core cooling systems (ECCS) by clogging the ECCS suction strainers. Proper maintenance of the Service Level I coating ensures that coating degradation will not impact the operability of the ECCS systems. The Protective Coating Monitoring and Maintenance program provides for coating system inspection, assessment, and repair for conditions that adversely affects the ability of Service Level I coatings to function as intended.

Service Level I coatings will prevent or minimize the loss of material due to corrosion, but these coatings are not credited for managing the effects of corrosion for the carbon steel drywell shell and components at NMP1. This program ensures only that the Service Level I coatings maintain adhesion so as to not affect the intended function of the 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 unqualified coating is controlled to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits.

NUREG-2191 Consistency

The Protective Coating Monitoring and Maintenance aging management program will be consistent with the ten elements of aging management program XI.S8, “Protective Coating Monitoring and Maintenance” specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Protective Coating Monitoring and Maintenance aging management program will be enhanced to:

1. Require personnel qualifications meet the requirements discussed in ASTM D 5163-08, paragraph 9. **Program Element Affected: Parameters Monitored or Inspected (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Protective Coating Monitoring and Maintenance program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed on the aging management activities in place for components within primary containment that are coated with Service Level I coatings. The purpose of the aging management program effectiveness review was to verify the intent of the existing aging management activities, which is to monitor and maintain Service Level I protective coatings inside the primary containment to ensure that the condition of the subject coatings does not impact operability of the emergency core cooling systems (ECCS).

The program effectiveness review was comprised of a review of industry, fleet, and site-specific operating experience, program implementing documents, and program related issue reports. Completed inspection results documented in engineering report NER-1S-045 were reviewed to ensure the objective of maintaining the quantity of degraded coatings in the containment is less than the amount permitted by the ECCS suction strainer debris loading calculation. In all cases, the quantity of degraded coatings has been found to meet these criteria, maintaining the ability of the ECCS to perform its intended function.

This operating experience provides objective evidence that the periodic assessments of the Protective Coating Monitoring and Maintenance aging management program are performed to identify and improve program elements to maintain program effectiveness.

2. During the 2023 refueling outage, visual inspections were performed in the drywell and torus by ANSI N45.2.6 certified level III inspectors. During the inspection, coating stabilization was performed, removing approximately 35 square feet of failed coating. Removing the failed coating reduces the amount available for transport to the ECCS suction strainers. The full inspection was documented, and the results were evaluated in engineering report NER-1S-045. The inspection conservatively identified 300 square feet of failed coating adding 7.8 pounds per cubic feet available for transport to the suction strainers.

The total amount of failed coating available for transport to the ECCS suction strainers is obtained by combining the quantity of failed coating identified in the 2021 refueling outage with the failed coatings identified in the 2023 refueling outage. To account for the potential that more failures may occur during the operating cycle the amount visually identified is conservatively increased by 20 percent. When compared to the limits established in the ECCS suction strainer loading calculation, the amount identified remains below the threshold with margin for future degradation.

This operating experience demonstrates that Service Level I coatings are inspected by qualified coating inspectors every refueling outage. Inspection results are evaluated by the coatings coordinator using the acceptance criteria, and coating maintenance, including coating stabilization to support continued

operability of the ECCS systems. The total unqualified coating is tracked and evaluated, future work and recommended actions are proposed by the coatings coordinator to be performed in subsequent outages.

3. During the 2011 refueling outage, degraded coatings on the drywell shell were removed and the coating was replaced at the 225' elevation in accordance with Nine Mile Point Engineering Specifications. The full perimeter of the shell was recoated from the floor to approximately 5-6 feet up the shell. Coating degradation at that elevation was previously identified and evaluated in the coating inspection engineering report. The area was cleaned, prepared, and the Service Level I coating was applied by qualified individuals to the manufacturer's specifications. Dry film thicknesses were documented to be within the acceptable ranges and the results were recorded in accordance with station procedures. The Protective Coating Monitoring and Maintenance program owner inspected the area prior to cleaning activities, during surface preparation, after the final application and documented the review in the coating inspection engineering report.

During the following refueling outage in 2013, the newly applied coating at the 225' elevation in the drywell was inspected and evaluated by the program owner. The inspection identified scattered small areas of coating that were cracking and peeling. The cause appeared to be due to poor surface cleaning. The estimated area of the cracking and peeling coating was added to the total amount of coating available for transportation to the ECCS suction strainers. The 225' elevation of the drywell is inspected and evaluated during each refueling outage and is documented in the coating inspection engineering report.

This operating experience provides objective evidence that Service Level I coatings are inspected by qualified coating inspectors every refueling outage. Inspection results are evaluated by the coatings coordinator using the acceptance criteria and coating maintenance including repair or replacement is initiated to support continued operability of ECCS systems.

The operating experience relative to the Protective Coating Monitoring and Maintenance program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of coating or liner integrity. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Protective Coating Monitoring and Maintenance program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Protective Coating Monitoring and Maintenance program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Protective Coating Monitoring and Maintenance program will provide reasonable assurance that the loss of coating or lining integrity aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.36 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 aging management program is an existing condition monitoring program that manages the effects of reduced insulation resistance of accessible electrical cable and connection insulation within the scope of license renewal subjected to an adverse localized environment during the subsequent period of extended operation.

In most areas of NMP1, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. An adverse localized environment (ALE) is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable or connection, including those that are coated with fire-retardant material. Electrical insulation used in electrical cables and connections may degrade more rapidly than expected in these adverse localized environments.

Adverse localized environments are identified through an integrated approach. This approach includes but is not limited to: the review of EQ program temperature, radiation, and moisture levels; recorded information from equipment or plant instrumentation; as-built and field walk down; a plant spaces scoping and screening methodology; and the review of industry and plant specific operating experience.

Accessible cables and connections located in adverse localized environments are managed by visual inspection. These cables and connections are visually inspected at least once every 10 years for cable jacket and connection insulation surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination that could indicate incipient conductor insulation aging degradation from temperature, radiation, or moisture. This is an adequate inspection frequency to preclude failures of the cable and connection insulation since operating experience shows that aging degradation is a slow process. Plant specific OE will be evaluated for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in scope cable and connection electrical insulation.

When deemed applicable, testing will be performed for identified occurrences of age degradation. Factors to be considered for selecting a sample include: the identified environmental parameters, voltage level, circuit loading, connection type, location, and the electrical insulation composition. The component sampling methodology utilizes a population that includes a representative sample of in scope cable and connection types regardless of whether the component was included in a previous aging management or maintenance program. The technical basis for sample selection will be documented.

The first inspection for subsequent license renewal will be completed prior to the subsequent period of extended operation. Testing will be considered as a follow up action if visual inspections identify degraded or damaged conditions for in scope cables and connections. When a large number of cables are identified as potentially degraded, a sample population will be tested. Testing may include thermography

and other proven condition monitoring test methods applicable to cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited in lieu of testing recommended in this AMP provided they can be shown to adequately assess the aged condition or health of the electrical insulation of in-scope cables and connections. Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the station's procedures.

Unacceptable visual indications of cable and connection electrical insulation anomalies are subject to an engineering evaluation under the corrective action program. Corrective actions include, but are not limited to, testing; shielding or otherwise mitigating the environment; relocating; or replacing 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.

NUREG-2191 Consistency

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be enhanced to:

1. Evaluate plant specific operating experience for previously identified and mitigated adverse localized environments' cumulative aging effects applicable to in-scope cable and connection insulation to confirm that the insulation's intended functions continue to be supported during the subsequent period of extended operation. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**
2. Perform testing of a sample population when a large number of cables are identified as degraded. The sample size will be 20 percent of each affected cable and connection type with a maximum sample size of 25. **Program Elements Affected: Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In September 2025, an effectiveness review was performed for the NMP1 Non-EQ Electrical Cables and Connections aging management program. The purpose of the program effectiveness review was to: 1) verify that detection of aging effects has (or should) occur with sufficient time to implement preventive actions before there is a loss of intended function; 2) verify that corrective actions, including cause evaluation and prevention of recurrence, are timely; 3) verify that industry operating experience and plant operating history, including corrective actions, are used to inform aging management programs; and 4) verify license renewal commitments or requirements are properly documented and maintained.

The program effectiveness review confirmed that all aging management program activities are being implemented as required. Adverse localized environments were identified and walkdowns were performed during the first period of extended operation. No conditions adverse to quality were identified for cables or connections in the scope of license renewal located in adverse localized environments. Issues that were identified during walkdowns were entered into the corrective action program. No aging management program deficiencies were identified by the program effectiveness review.

This operating experience example provides objective evidence that program effectiveness reviews of the NMP1 Non-EQ Electrical Cables and Connections aging management program are performed to ensure effective program implementation. This effectiveness review did not identify any areas that need to be improved to maintain effective performance of the program. This operating experience provides objective evidence that this aging management program has effectively managed potential reduction in electrical insulation resistance for cables and connections in the scope of license renewal.

2. In March 2017, NMP1 walkdowns were performed for the Non-EQ Electrical Cables and Connections aging management program. Accessible cable and connection insulation located in adverse localized environments was inspected for cable jacket and insulation surface anomalies. The walkdowns were performed satisfactorily with no cable jacket or connection insulation surface anomalies identified.

One deficiency was identified, which is outside the scope of the Non-EQ Electrical Cables and Connections aging management program. The outer coating of a section of flex conduit was found cracked and peeling away in the offgas charcoal column room. An issue report was generated to identify and correct this deficiency.

This operating experience provides objective evidence that walkdowns are performed at NMP1 to inspect accessible cable and connection insulation located

in adverse localized environments for cable jacket and insulation surface anomalies. It also provides objective evidence that issue reports are generated to identify and correct deficiencies during these walkdowns.

3. In October 2023, cables located in the Unit 1 south reheater room were exposed to abnormal temperatures, increased dose rates, and a high moisture environment as the result of steam leaks in the room. The potential impact on the cables located in this area was recognized and emergent insulation resistance testing was performed. The initial insulation test results were satisfactory, however the need to perform additional testing to further assess the overall impact of the steam leaks on the health of the cable insulation was recognized. The issue was captured in the corrective action program to document the observed condition, the results of the testing performed during the initial investigation, and to recommend additional testing to further assess cable health. A work order has been generated to implement the recommended testing after being prioritized and screened for plant risk.

This operating experience provides objective evidence that the potential impact of the adverse environment on cable insulation was recognized. It also provides objective evidence of the site's commitment to assessing the condition of cable insulation located in adverse environments to ensure any aging effects are identified such that appropriate corrective actions can be taken prior to loss of intended function.

The operating experience relative to the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including reduced electrical insulation resistance. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the reduced electrical insulation resistance aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.37 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 aging management program is an existing performance monitoring program. This aging management program manages the effects of reduced insulation resistance of non-EQ cable and connection electrical insulation in instrumentation circuits with sensitive, high-voltage, low-level current signals and that are subjected to adverse localized environments (ALEs) caused by temperature, radiation, or moisture. The program applies to the in scope non-EQ portions of the neutron monitoring system, area and process radiation monitoring system, and control room ventilation system.

Exposure of electrical cables to adverse localized environments can result in reduced insulation resistance causing increases in leakage currents. A reduction in insulation resistance is a concern for circuits with sensitive, high-voltage, low-level current signals because reduced insulation resistance may contribute to signal inaccuracies.

Calibration or surveillance testing results will be periodically reviewed for the in scope circuits when the cables are included as part of the calibration or surveillance circuit. These reviews will provide an indication of the existence of aging effects based on acceptance criteria for instrumentation circuit performance. Review of results obtained during normal calibration and surveillance may detect severe aging degradation prior to the loss of the cable and connection intended function.

A proven cable test (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition) will be performed for the in scope circuits when the cables are not included as part of the calibration or surveillance or as an alternative to the review of calibration or surveillance results. Insulation resistance testing will not be used solely for detecting deterioration of electrical insulation systems.

Individual calibration and cable test results that do not meet acceptance criteria are evaluated in the corrective action program.

Periodic review of calibration or surveillance results will be performed at least once every 10 years during the subsequent period of extended operation. If cable tests are credited for program implementation, cable test frequency will be based on engineering evaluation and will be performed at least once every 10 years.

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are applicable to all Constellation plants. The equivalent Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program for Peach

Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program will be consistent with the ten elements of aging management program XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits aging management program will be enhanced to:

1. Add the electrical cables and connections for the following neutron monitors to the scope of the program:

- a. Source range monitors

Program Elements Affected: Scope of Program (Element 1), Preventative Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6)

2. Add the electrical cables and connections for the following radiation monitors to the scope of the program:

- a. Reactor building ventilation radiation monitors

Program Elements Affected: Scope of Program (Element 1), Preventative Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6)

3. Review calibration or surveillance results of circuits in the scope of this program at least once every 10 years. The first periodic review will be performed prior to the subsequent period of extended operation. **Program Elements Affected: Scope of Program (Element 1), Preventative Actions (Element 2), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects**

(Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6)

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Reviews and tests that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

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 will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In September 2025, an aging management program effectiveness review was performed on the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits. The effectiveness review was performed to verify that detection of aging effects allows sufficient time to implement corrective actions before loss of intended function, verify that corrective actions are timely, verify that industry and plant operating experience are used to inform AMP's, and verify license renewal commitments are properly managed.

The effectiveness review concluded that the aging management program is effectively managing aging effects of in scope cables and connections to ensure a loss of function does not occur. Calibration and surveillance results have been reviewed for indication of the existence of aging effects. Cable tests have been performed when the cables located in ALE's are not included as part of the calibration or surveillance. The reviews and tests performed during the first license renewal period of extended operation have not identified age-related degradation of electrical cable and connection insulation. All license renewal implementation activities have been performed in the required periodicities. No strengths, recommendations, or deficiencies were identified by the effectiveness review.

This operating experience example provides objective evidence that program effectiveness reviews of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits aging management program are performed to ensure continuous improvement in program implementation. This effectiveness review did not identify any areas that need to be improved to maintain effective performance of the program. In addition, this operating experience provides objective evidence that this aging management program has effectively managed potential reduction in electrical insulation resistance for in scope cables and connections.

2. In March 2025, during an engineering walkdown under vessel it was identified that the condition of the cable jacket on each of the source range monitors (SRMs) and intermediate range monitors (IRMs) were degraded due to repeated

insertion and withdrawal. An issue report was generated to recommend that all four SRM and all eight IRM cables from the penetration to the detector connector be replaced. A phased approach was planned and approved by the project review committee, and multiple work orders were created to replace the degraded cables over the next two refueling outages.

This operating experience example provides objective evidence that the corrective action program is used to initiate the planning and funding for cable replacements required to improve the overall health of the system. It also provides objective evidence that the station is committed to assessing the condition of cable insulation located in adverse environments to ensure any material conditions are identified such that appropriate corrective actions can be taken prior to loss of intended function.

3. In June 2019, while performing the routine calibration of the emergency condenser vent radiation monitors, it was found that the detector connector/cable was degraded. The degraded connector/cable was replaced, and the calibration was completed satisfactorily. The degraded connector/cable did not result in a loss of intended function.

This operating experience example provides objective evidence that calibrations are being effectively performed in the first period of extended operation, and when cable degradations are found, the corrective action program is utilized to implement corrective actions to resolve.

The operating experience relative to the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program did not identify an adverse trend in performance. The cable testing methods being implemented by the program have been proven effective in detecting aging effects including reduced electrical insulation resistance. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program will provide reasonable assurance that the reduced electrical insulation resistance aging effect is adequately managed so that the intended functions of components within the scope of license renewal are maintained

consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.38 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 aging management program is an existing condition monitoring program. This program will manage the effects of reduced insulation resistance of non-EQ, inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), medium-voltage power cables (operating voltage; 2 kV to 35 kV), that are within the scope of license renewal and potentially exposed to significant moisture. For this program, 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.

The cables within the scope of this program are tested using one or more proven tests for detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence, such as dielectric loss (dissipation factor or power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state of the art at the time the test is performed. The first tests will be completed prior to the subsequent period of extended operation. Cables will be tested at least once every six years. More frequent testing may occur based on test results and operating experience.

There are no inaccessible medium-voltage power cables designed for continuous wetting or submergence installed at NMP1 within the scope of SLR.

Periodic inspections will be performed to prevent inaccessible cables from being exposed to significant moisture. In scope handholes will be inspected for water accumulation. Accumulated water will be removed as needed. The frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence. The first inspections will be completed prior to the subsequent period of extended operation. During the subsequent period of extended operation, the inspections will occur following event driven occurrences and at least once per year. The periodic inspection will include documentation whether manual pumping is effective in preventing cable exposure to significant moisture.

Cable testing and in scope handhole inspection results not meeting the acceptance criteria will be evaluated in the corrective action program.

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program. The program requirements are generally applicable to all Constellation plants, with certain aspects limited to operation beyond 60 years. The equivalent Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program for Peach Bottom Atomic Power Station, including the aspects of the program applicable

to operation beyond 60 years, has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be enhanced to:

1. Perform cable testing of the circuits in the scope of this program at a frequency of at least once every six years. The first periodic test will be performed prior to the subsequent period of extended operation. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**
2. Perform inspections for water accumulation in handholes in the scope of this program after event driven occurrences that could result in water accumulation and cable submergence. **Program Element Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3)**
3. Perform annual inspections for water accumulation in handholes in the scope of this program. The first periodic inspection will be performed prior to the subsequent period of extended operation. **Program Elements Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Tests and inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

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 will continue to be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. NMP1 SLR project activities included validating station system, structures, and components (SSCs) credited by the current licensing basis (CLB) for compliance with 10 CFR 50.48, "Fire protection." In June 2014, during the NMP1 first period of extended operation, the NRC issued a safety evaluation that transitioned the existing NMP1 Fire Protection Program to a risk-informed, performance-based program based on NFPA 805 pursuant to 10 CFR 50.48(c).

To support NFPA 805 non-power operations, NMP1 can be configured to backfeed the plant ac electrical systems from the 345KV transmission system via the station service transformer to provide an alternate source of 4.16KV power. In the backfeed configuration, the 24KV generator leads medium voltage cables provide the primary current path from the isophase bus to the station service transformer.

A review of station engineering specifications did not identify the 24KV generator leads as being credited for NMP1 NFPA 805. The omission in the engineering specification resulted in NMP1 not identifying a first license renewal aging management program for medium voltage cables.

This condition was previously identified during a 2018 license renewal aging management program effectiveness review of the medium voltage cable program for the station. The review confirmed normal testing and inspections were performed on the identified 24KV cables with tan delta testing performed in 2011 and 2017. However, the omission was not clearly captured in the final effectiveness review report. The need to revise the engineering specification and update the medium-voltage cable program to include NMP1 was identified in the effectiveness review and entered into the corrective action program. However, the corrective action was closed to actions performed within the NMP1 cable condition monitoring program without the engineering specifications being updated to include the NMP1 24KV generator leads medium-voltage cables.

In 2023, an engineering technical evaluation was approved in support of the NMP cable condition monitoring program. The technical evaluation contains a third-party study of Unit 1 and Unit 2 cables to identify all critical cables subjected to adverse local environments. The technical evaluation confirmed NMP1 24KV generator leads medium-voltage cables are routed underground and are identified as critical cables in the NMP1 cable condition monitoring program. The technical evaluation validated the need to update UFSAR, Appendix C and the engineering specification to include NMP1 24KV generator leads medium-voltage cables.

The inconsistencies identified above were captured in the corrective action program in 2025 to evaluate the need to revise the engineering specifications to include NMP1 24KV generator leads medium-voltage cables and the need to

revise NMP1 UFSAR, Appendix C to include an aging management program for Inaccessible Non-EQ Medium-Voltage Cables. The testing on these medium-voltage cables meets the requirements of XI.E3A, "Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG-2191. Therefore, there are no concerns about the present condition of the cables.

This operating experience example provides objective evidence that the corrective action program is used to implement improvements in the aging management of inaccessible power cables.

2. In October 2020, a fleet cable program check-in self-assessment was performed. The objective of the check-in assessment was to validate compliance with the fleet cable program. The check-in assessment criteria was taken from the revision of the fleet procedure accepted at the station for the cable program at the time of the assessment. Overall, the check-in found a lack of evidence demonstrating how stations determined if any critical cables were affected by adverse environments. Specifically, a gap identified in the check-in assessment found that stations had incomplete lists of identified adverse environments and lacked consistency when compared to similar sites. The action to close this gap required stations to identify all adverse environments and compare results to adverse conditions identified at similar stations for consistency.

At NMPNS, the gap was closed by developing an engineering technical evaluation. The technical evaluation confirmed that NMP1 has three 24KV inaccessible medium-voltage cables categorized as critical by the cable condition monitoring program that are subjected to an adverse local environment (ALE) caused by possible exposure to significant moisture.

NMP1 SLR project activities identified cable condition monitoring program preventive maintenance testing history for the three 24KV inaccessible medium-voltage cables, performed on a six-year frequency, with acceptable test data obtained. The test frequency for the 24KV cables was adjusted to six years from 10 years after test results obtained in 2011 were evaluated in the corrective action program. The first test at the six-year frequency was performed in 2017. The most recent testing was completed in 2021 with acceptable results obtained. The 24KV cables were added to the medium-voltage cable program based on operating experience from NMP2 when a concern was raised during an NRC Component Design Basis Inspection (CDBI) with NMP2 service water inaccessible medium-voltage cables. The medium-voltage cable program was originally developed in response to NRC Generic Letter 07-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients."

This operating experience provides objective evidence that the fleet cable aging management program has effectively managed any potential reduction in electrical insulation resistance for in scope, non-EQ, inaccessible, medium-voltage power cables. This operating experience also demonstrates application of the corrective action program to ensure that these circuits are able to continue to perform their intended functions and that appropriate aging management is performed during the subsequent period of extended operation.

3. In February 2023, NMP1 initiated an improvement project to install metal enclosed bus from the main generator isophase bus to the station service transformer, eliminating the 24KV cables used to feed the station service transformer. The existing 24KV cables are routed underground from the turbine building to the transformer. This configuration potentially exposes the cables to significant moisture.

Currently, the 24KV cables are included in the NMPNS cable condition monitoring program as critical cables with tan delta testing performed on a six-year frequency.

The station service transformer metal enclosed bus project is targeted to be completed during the spring 2027 refueling outage.

This operating experience provides objective evidence that the station is taking action to eliminate medium-voltage power cables routed through adverse local environments to ensure that these circuits are able to continue to perform their intended functions and that appropriate aging management is performed during the subsequent period of extended operation.

The operating experience related to the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The test methods being implemented by the program have been proven effective in detecting aging effects including reduced insulation resistance from exposure to significant moisture. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program are performed to identify the areas that need improvement to maintain the effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the reduced electrical insulation resistance or degraded dielectric strength aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.39 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 aging management program is a new condition monitoring program. This program manages the effects of reduced insulation resistance of non-EQ, inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables that are within the scope of license renewal and potentially exposed to significant moisture. For this program, 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.

There are no inaccessible instrument and control cables designed for continuous wetting or submergence installed at NMP1 within the scope of SLR.

Periodic inspections will be performed to prevent inaccessible cables from being exposed to significant moisture. In scope manholes and associated accessible conduit ends will be inspected for water accumulation. Accumulated water will be removed as needed. The frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence. During the subsequent period of extended operation, the inspections will occur at least once per year and following event driven occurrences. The periodic inspections will include documentation that either automatic or passive drainage systems or manual pumping are effective in preventing cable exposure to significant moisture.

In scope, inaccessible instrument and control cables that are accessible during manhole inspections will be visually inspected at least once every six years. Inspections may be performed concurrent with water accumulation inspections. Cables that are found to be exposed to significant moisture will be evaluated to determine if testing is required. If testing is recommended, initial one-time testing is performed on a sample population to assess the insulation condition.

Testing and inspection results that do not meet the acceptance criteria are evaluated in the corrective action program.

The new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification

Requirements program is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E3B, "Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

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 ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2023, inconsistent data was obtained during current transformer (CT) network testing performed as part of activities to replace a remote terminal unit at NMP1. Further investigation identified an unexpected low resistance to ground. Technicians performed megger testing to isolate the observed condition to the four "A" phase CTs for the NMP1 breaker connecting a reserve transformer to the 115KV Line offsite power circuit, Nine Mile Point – FitzPatrick #4.

The technicians generated an issue report (IR) to capture the observed condition in the corrective action program. They included an analysis of each CT network in the IR to identify the potential consequences associated with a postulated failure of the "A" phase CT in that network. The worst-case consequence identified being inadvertent actuation of bus differential relaying and the associated lock-out of all bus breakers.

After satisfactorily testing each suspect “A” phase CT, reviewing recent oil sample test result, and then considering the logistics and coordination required to replace the suspect “A” phase CTs emergently, a follow-up IR was generated for replacement in a future refueling outage. Although CT replacement in a future refueling outage adds risk, it also provides additional time to obtain required replacement parts, align resources and better coordinate the evolution.

This operating experience example provides objective evidence demonstrating the corrective action program is being effectively used to document and track resolution of identified issues. It provides objective evidence of the station’s application of testing methods to better understand unexpected results obtained during maintenance activities. It also demonstrates the station’s commitment to assessing the condition of cable insulation located in adverse environments to ensure any aging effects are identified such that appropriate corrective actions can be taken prior to loss of intended function.

2. In 2020, a fleet cable program check-in self-assessment was performed to validate compliance with the Constellation fleet cable condition monitoring procedures. In addition to providing guidance for aging management of cables within the scope of the license renewal program, the cable condition monitoring procedures also provide guidance for management of critical cables located in adverse environments. These procedures establish the requirements to monitor critical cables in adverse environments to determine cable health and to proactively replace degraded cables prior to failure. Critical cables within the scope of the program include medium-voltage, low-voltage, and instrument and control. The check-in self-assessment found NMP1 was not in full compliance with the fleet cable condition monitoring procedures with respect to management of critical cables in adverse environments.

In 2021 and because of the fleet cable program check-in self-assessment, NMP1 developed an action plan to close gaps to full compliance with the fleet cable condition monitoring procedure requirements. The action plan was reviewed with the corporate cable program engineer and a consensus was reached on a total of five actions to be taken at NMPNS to address gaps impacting NMP1. The five actions include: 1) perform a review of the NMP1 and NMP2 Edison databases and verify all critical cables located in adverse environments have been identified and appropriately screened, 2) perform a corrective action program review of the past two operating cycles at each unit for station IRs identifying adverse conditions in proximity to critical cables (leaks, temperature variations, etc.), 3) add all required cable data to the Cable Aging Management Software (CAMP) database, 4) perform risk ranking of each cable in scope of the cable monitoring program and assess the station replacement readiness for each critical cable in the scope of the program, and 5) update station specific cable walkdown procedures and job plans to incorporate EPRI Technical Report 1011223, “Aging Identification and Assessment Checklist: Electrical Components,” and EPRI Technical Report 3002002994, “Plant Engineering: Field Cable for Harvesting Service-Aged Cable (Cable Harvesting Guide).”

The 2021 NMP1 action plan items were integrated into the 2020 fleet cable program check-in self-assessment gap actions. NMP1 has completed all action plan items identified in the 2021 action plan as well as the 2020 fleet cable

program check-in self-assessment gap actions. Resolution of these issues brought NMP1 into full compliance with the fleet cable condition monitoring procedures. Procedure compliance will provide NMP1 additional insight into the overall health of cable insulation at the station as the cables age.

This operating experience example provides objective evidence that self-assessments are utilized to identify weaknesses or gaps within the cable condition monitoring practices in order to drive continuous improvement. Further, this example demonstrates that the corrective action program is effectively used to document and track resolution of identified gaps. It also provides objective evidence of the station's commitment to assessing the condition of cable insulation located in adverse environments to ensure any aging effects are identified such that appropriate corrective actions can be taken prior to loss of intended function.

Additional operating experience information for manholes containing in scope, inaccessible instrument and control cables is contained within the operating experience discussions in SLRA Sections B.2.1.38 and B.2.1.40, which describe the inaccessible medium-voltage power cables and the inaccessible low-voltage power cables aging management programs. These operating experience examples include improvement initiatives for manholes and plant-initiated cable condition monitoring activities for inaccessible cables.

The operating experience related to the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The test methods that will be implemented by the program have been proven effective in detecting aging effects including reduced insulation resistance from exposure to significant moisture. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be performed to identify the areas that need improvement to maintain the effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant specific and industry operating experience. Therefore, there is confidence that 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 the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the reduced electrical insulation resistance or degraded dielectric strength aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.40 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 aging management program is a new condition monitoring program. This program manages the effects of reduced insulation resistance of non-EQ, inaccessible or underground (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) that are within the scope of license renewal and potentially exposed to significant moisture. For this program, 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.

There are no inaccessible low-voltage power cables designed for continuous wetting or submergence installed at NMP1 within the scope of SLR.

Periodic inspections will be performed to prevent inaccessible cables from being exposed to significant moisture. In scope manholes and associated accessible conduit ends will be inspected for water accumulation. Accumulated water will be removed as needed. The frequency of inspections for accumulated water will be established and adjusted based on plant-specific operating experience with cable wetting or submergence. During the subsequent period of extended operation, the inspections will occur at least once per year and following event driven occurrences. The periodic inspections will include documentation that either automatic or passive drainage systems or manual pumping are effective in preventing cable exposure to significant moisture.

In scope inaccessible low-voltage power cables that are accessible during manhole inspections will be visually inspected at least once every six years. Inspections may be performed concurrently with water accumulation inspections. Cables that are found to be exposed to significant moisture will be evaluated to determine if testing is required. If testing is recommended, initial one-time testing is performed on a sample population to assess the insulation condition.

Testing and inspection results that do not meet the acceptance criteria are evaluated in the corrective action program.

The new Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new Electrical Insulation for Inaccessible Low-Voltage Power

Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the new Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E3C, "Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

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 ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2020, a fleet cable program check-in self-assessment was performed to validate compliance with the Constellation fleet cable condition monitoring procedures. In addition to providing guidance for aging management of cables within the scope of the license renewal program, the cable condition monitoring procedures also provide guidance for management of critical cables located in adverse environments. These procedures establish the requirements to monitor critical cables in adverse environments to determine cable health and to proactively replace degraded cables prior to failure. Critical cables within the scope of the program include medium-voltage, low-voltage, and instrument and control. The check-in self-assessment found NMP1 was not in full compliance with the fleet cable condition monitoring procedures with respect to management of critical cables in adverse environments.

In 2021 and because of the fleet cable program check-in self-assessment, NMP1 developed an action plan to close gaps to full compliance with the fleet cable condition monitoring procedure requirements. The action plan was reviewed with the corporate cable program engineer and a consensus was reached on a total of five actions to be taken at NMPNS to address gaps impacting NMP1. The five actions include: 1) perform a review of the NMP1 and NMP2 Edison databases and verify all critical cables located in adverse environments have been identified and appropriately screened, 2) perform a corrective action program review of the past two operating cycles at each unit for station IRs identifying adverse conditions in proximity to critical cables (leaks, temperature variations, etc.), 3) add all required cable data to the Cable Aging Management Software (CAMP) database, 4) perform risk ranking of each cable in scope of the cable monitoring program and assess the station replacement readiness for each critical cable in the scope of the program, and 5) update station specific cable walkdown procedures and job plans to incorporate EPRI Technical Report 1011223, "Aging Identification and Assessment Checklist: Electrical Components," and EPRI Technical Report 3002002994, "Plant Engineering: Field Cable for Harvesting Service-Aged Cable (Cable Harvesting Guide)."

The 2021 NMP1 action plan items were integrated into the 2020 fleet cable program check-in self-assessment gap actions. NMP1 has completed all action plan items identified in the 2021 action plan as well as the 2020 fleet cable program check-in self-assessment gap actions. Resolution of these issues brought NMP1 into full compliance with the fleet cable condition monitoring procedures. Procedure compliance will provide NMP1 additional insight into the overall health of cable insulation at the station as the cables age.

This operating experience example provides objective evidence that self-assessments are utilized to identify weaknesses or gaps within the cable condition monitoring practices in order to drive continuous improvement. Further, this example demonstrates that the corrective action program is effectively used to document and track resolution of identified gaps. It also provides objective evidence of the station's commitment to assessing the condition of cable insulation located in adverse environments to ensure any aging effects are identified such that appropriate corrective actions can be taken prior to loss of intended function.

Additional operating experience information for manholes containing in scope, inaccessible low-voltage power cables is contained within the operating experience discussions in the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38) program and the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39) program. These operating experience examples include improvement initiatives for manholes and plant initiated cable condition monitoring activities for inaccessible cables.

The operating experience related to the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program did not identify an adverse trend in performance. The test methods that will be implemented by the program have been proven effective in

detecting aging effects including reduced insulation resistance from exposure to significant moisture. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant specific and industry operating experience. Therefore, there is confidence that 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 the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the reduced electrical insulation resistance or degraded dielectric strength aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.41 Metal Enclosed Bus**Program Description**

The Metal Enclosed Bus aging management program is an existing condition monitoring program, which relies on sample-based inspections to manage the identified aging effects of in scope metal enclosed bus. The internal portions of the accessible bus enclosure assemblies are visually inspected for age-related degradation, including 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.

External surfaces in an outdoor environment are visually inspected for loss of material due to general pitting and crevice corrosion. Accessible enclosure assembly elastomers are visually inspected for age-related degradation, including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, or loss of strength.

Metal enclosed bus external structural supports are managed by the Structures Monitoring (B.2.1.33) program.

A sample of accessible bolted connections is inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro-ohmmeter. The sample will be 20 percent of the population, with a maximum sample size of 25. Inspection of a sample population of bolted connections will be performed at least once every 10 years during the subsequent period of extended operation.

The first inspections and tests for subsequent license renewal will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Metal Enclosed Bus aging management program will be consistent with the ten elements of aging management program XI.E4, “Metal Enclosed Bus,” specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Metal Enclosed Bus program will be enhanced to:

1. Perform periodic inspections of the isophase bus from the main generator to the main step-up transformers to the station service transformer and a sample of

metal enclosed bus bolted connections. The first periodic inspection will be performed prior to the subsequent period of extended operation. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Metal Enclosed Bus aging management program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program effectiveness review was performed on the Metal Enclosed Bus aging management program. The purpose of the program effectiveness review was to verify that the existing aging management program activities were being effectively implemented in the first license renewal period of extended operation. These activities included periodic inspection of bus ducts that are in the scope of license renewal, documentation of findings, and follow-up actions in the corrective action program.

A sample of issue reports written on SSCs within the scope of the Metal Enclosed Bus aging management program were reviewed. Issue reports that were generated during performance of aging management activities were also reviewed to determine if age-related degradation or loss of intended function had been identified. This assessment also included verification of both scope and frequency of the aging management activities.

The program effectiveness review confirmed that all aging management program activities were being effectively implemented. No loss of intended function resulting from age-related degradation was identified. No required changes to sampling size or location, or changes to inspection frequency were identified. No deficiencies were identified by the program effectiveness review.

This operating experience example provides objective evidence that program effectiveness reviews of the Metal Enclosed Bus aging management program are performed to ensure continuous improvement of program implementation. This effectiveness review did not identify any areas needing improvement to maintain effective performance of the program.

2. During NMP1 subsequent license renewal (SLR) project activities, inconsistencies were identified while validating electrical power current paths to equipment credited by NMP1 first license renewal (FLR). Specifically, the main generator isophase bus provides the primary current path to the station service transformer, which was in scope for FLR, to provide an additional source of offsite power. However, neither the approved station engineering specification nor the equipment database identify the isophase bus as being in scope for NMP1 FLR.

Nine Mile Point Nuclear Station, Unit 1 SLR project activities also include identifying station SSCs credited by the current licensing basis (CLB) for compliance with 10 CFR 50.48, “Fire protection.” In June 2014, during the NMP1 first period of extended operations, the NRC issued a Safety Evaluation that transitioned the existing NMP1 Fire Protection Program to a risk-informed, performance-based program based on NFPA 805, pursuant to 10 CFR 50.48(c). The isophase bus provides the primary current path to station service transformer credited by NFPA 805 non-power operations while NMP1 is configured to back feed from the 345KV transmission system. However, neither approved station engineering specifications nor the equipment database identify the isophase bus as being in scope for NMP1 FLR for NFPA 805.

The inconsistencies identified above were captured in the corrective action program to evaluate the need to revise the engineering specifications to include NMP1 isophase bus and to update the preventive maintenance to implement the FLR Metal Enclosed Bus aging management program inspection requirements.

This operating experience example provides objective evidence that the corrective action program is used to implement improvements in the aging management of metal enclosed bus.

3. In 2013, during performance of license renewal preventive maintenance inspection, degraded conditions were observed on nonsegregated bus for a reserve transformer. Specifically, sections of the nonsegregated bus insulation were found to show indications of cracking. The observed condition was captured in the corrective action program and a work order was generated to drive repairs. The repairs were completed with satisfactory results and the reserve transformer was returned to service.

This operating experience example provides objective evidence that testing has been performed by the station to proactively identify MEB deficiencies. This testing has confirmed that the MEB is in good overall condition, and that the station’s existing program has been effective in maintaining the health of the MEB that is within the scope of subsequent license renewal.

The operating experience relative to the Metal Enclosed Bus program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including increased electrical resistance of connection, loss of material, surface cracking, crazing, scuffing, dimensional change, shrinkage, discoloration, hardening, loss of strength, and reduced electrical insulation resistance. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Metal Enclosed Bus program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Metal Enclosed Bus program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Metal Enclosed Bus program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.42 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 aging management program is a new condition monitoring program. The program will implement one-time testing of a representative sample of non-EQ electrical cable connections to ensure that either increased resistance of connection is not occurring or that the existing preventive maintenance program is effective such that a periodic inspection program is not required. This one-time program will provide additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. This one-time program will also confirm that there are no aging effects requiring management during the subsequent period of extended operation. A representative sample of non-EQ electrical cable connections will be selected for one-time testing considering voltage level (medium and low voltage), circuit loading (high loading), connection type, and location (high temperature, high humidity, and vibration). The sample tested will be 20 percent of each connector type population with a maximum sample size of 25 connections.

The specific type of test performed will be a proven test method for detecting increased resistance of connections, such as thermography, contact resistance measurement, or another appropriate test without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc. The acceptance criteria will be specific for each type of test and the specific type of cable connections tested. Temperature measured by thermography will be evaluated against baselines, if available, or similarly configured components. Connections which cannot be adequately assessed by thermography will be assessed by contact resistance measurement or another appropriate test. The justification and technical basis for not performing subsequent periodic testing will be documented. Results that do not meet the acceptance criteria will be addressed in the corrective action program. The program will not implement visual inspections of cable connection insulation materials as an alternative to testing.

The new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be implemented in accordance with fleet procedures and the program requirements are expected to be applicable to all Constellation plants for operation beyond 60 years. The equivalent new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program for Peach Bottom Atomic Power Station (PBAPS) has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). The NMP1 commitment for the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is comparable to the associated PBAPS commitment. Based on the NRC's evaluation of the PBAPS program, the NRC has determined that the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will adequately manage the effects of aging such that intended function(s)

are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

The new aging management program will be implemented no later than six months prior to the subsequent period of extended operation. Tests and evaluations that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the ten elements of aging management program XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In April 2020, during routine thermography performed in a protective relay cabinet, elevated temperatures were identified on reactor protection system load protection contactors. The observed condition was documented in the corrective action program, compared to acceptance criteria in the fleet thermography procedure, and initially classified as unacceptable. After engaging engineering, it was observed that a combination of the relay configuration and the angle of the thermography camera during data gathering may have allowed internal temperature data to influence the surface temperature data originally taken. A plan was developed to obtain thermography data from the corresponding components in the other logic train. The additional thermography data taken on components in the other logic train was compared to the original data in question, reviewed with the fleet subject matter expert, and determined to be acceptable.

This operating experience provides objective evidence of NMP1 using thermography data from the preventive maintenance program to identify a potentially degraded condition, then using the corrective action program to develop and implement actions to address the observed condition prior to system functionality being adversely affected.

2. In July 2019, while taking digital low resistance ohmmeter (DLRO) measurements in accordance with a routine battery inspection procedure, technicians noticed movement in three out of four electrical connections tested. Additionally, as-found DLRO results outside of established acceptance criteria were obtained for the suspect connections. During the inspection and in accordance with the inspection procedure, the technicians performed a torque check of the fasteners making up the suspect connections. As-left DLRO measurements taken after completing the torque checks met established acceptance criteria in the inspection procedure.

The unexpected conditions observed during the battery inspection procedure, the torque check performed and the as-left DLRO results following the torque check were documented in a corrective action program issue report. A follow-up review of the issue report concluded the inspection procedure successfully identified the degraded condition prior to system functionality being adversely affected.

This operating experience provides objective evidence of NMP1 using DLRO data from a preventive maintenance routine inspection to identify a degraded condition and implement actions to address the degraded condition. The corrective action program was then used to drive review and evaluation of the observed condition by site engineering staff.

3. In August 2018, routine thermography of the NMP1 generator step-up transformer identified an elevated temperature on the load side of a cooling bank breaker. The maximum temperature difference observed was 60 degrees Celsius. Follow-up thermography showed the maximum temperature difference had lowered to 47 degrees Celsius and visual inspection of the suspect connection did not identify any anomalies.

An Adverse Condition Monitoring Plan was developed to establish periodic monitoring of the elevated temperature condition and to establish steady-state threshold temperatures with corresponding actions. A risk assessment was also developed and identified margin to the temperature where potential conductor insulation damage might be observed, and the condition was not creating an immediate challenge to reliable operations. Follow-up investigation activities isolated the elevated temperature to the cooling bank emergency power automatic transfer switch.

The condition was resolved during the spring 2019 NMP1 refueling outage when a broken sensing wire was identified. The broken wire was spliced to eliminate the elevated temperature.

This operating experience provides objective evidence of NMP1 using thermography data from the preventive maintenance program to identify a potentially degraded condition, then using the corrective action program to develop and implement actions to address the observed condition prior to system functionality being adversely affected.

The operating experience relative to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging

effects, including increased electrical resistance of connection. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the increased electrical resistance of connection aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.2 Plant-Specific Aging Management Programs

None. Nine Mile Point Nuclear Station, Unit 1 does not include plant-specific aging management programs.

B.3 NUREG-2191 Chapter X Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter X programs credited for managing the effects of aging.

B.3.1 Evaluation of Chapter X Aging Management Programs

Aging Management Programs evaluated in Chapter X of NUREG-2191 are associated with Time-Limited Aging Analysis for fatigue monitoring, neutron fluence monitoring, and environmental qualification of electric equipment. These programs are evaluated in this section.

B.3.1.1 Fatigue Monitoring

Program Description

The Fatigue Monitoring aging management program is an existing program that manages fatigue damage of reactor pressure vessel components, reactor coolant pressure boundary piping components, and other components subject to the reactor coolant, treated water, steam, condensation, diesel exhaust, air-outdoor, and air-indoor uncontrolled environments. Components that are managed by the program are fabricated from carbon steel, low alloy steel, stainless steel, nickel alloy, and inconel alloy.

The Fatigue Monitoring aging management program is a program that monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the cumulative usage factor (CUF) and environmentally adjusted cumulative usage factor (CUF_{en}) for each analyzed component does not exceed the applicable limit through the subsequent period of extended operation. The program monitors and tracks the number and severity of thermal and pressure transients for NMP1 as specified in UFSAR Section V.A.4.0, Table V-2, "Operating Cycles and Transient Analysis Results." No NMP1 ANSI B31.1 or ASME Code Class 2 and 3 maximum allowable stress range reduction/expansion stress analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii); therefore, this program does not apply to these implicit analyses. There is one dispositioned cycle-based fatigue flaw growth analysis for the feedwater and control rod drive return line (CRDRL) nozzles that is monitored by this program. There are no fracture mechanics analyses monitored by this program. No ASME Section III fatigue waiver or exemption analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii); therefore, this program does not apply to fatigue waiver or exemption analyses. The program also monitors applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations.

The program utilizes SI:FatiguePro™ Version 4.0 which is a computerized data acquisition, recording, and tracking software program. SI:FatiguePro™ is used to determine the overall cumulative number of transients that have occurred at a given

time and determines the CUF values resulting from the combination of transient occurrences. The program monitors the environmental effects of reactor coolant on Class 1 components by using the guidance in Regulatory Guide 1.207, "Guidelines for Evaluating Fatigue Analyses Incorporating the Life Reduction of Metal Components Due to the Effects of Light-Water Reactor Environment for New Reactors;" applicable fatigue curves in NUREG/CR-6909, Revision 1, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials;" and calculated alternating stress values from the existing ASME Code fatigue calculations to determine CUF_{en} values. SI:FatiguePro™ performs "stress-based" and "cycle-based" fatigue monitoring. The cumulative CUF and CUF_{en} values for the components monitored by SI:FatiguePro™ are compared to appropriate allowable limits (e.g., 1.0 for ASME Section III locations or 1.0 for CUF_{en} environmental fatigue locations). Prior to exceeding 80 percent of the allowable limit, corrective action is taken to review the applicable fatigue analyses and take appropriate actions to prevent exceeding the limit.

This program verifies the continued acceptability of existing fatigue analyses through transient occurrence counting and calculation of cumulative CUF and CUF_{en} values to demonstrate that they continue to meet the appropriate limits. The program requires comparison of actual event parameters to the applicable design transient definitions to ensure the actual transient is bounded by the applicable design transient. CUF and CUF_{en} values are computed parameters used to assess the likelihood of fatigue damage. Fatigue crack initiation is assumed to begin in a mechanical or structural component when the CUF or CUF_{en} values reach the value of 1.0.

NUREG-2191 Consistency

The Fatigue Monitoring aging management program is consistent with the ten elements of aging management program X.M1, "Fatigue Monitoring" specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Fatigue Monitoring aging management program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation:

1. In 2025, a periodic self-assessment was completed to review the effectiveness of the NMP1 Fatigue Monitoring aging management program and concluded that the NMP1 AMP is effectively managing aging effects of in scope SSCs to ensure a loss of function does not occur. This was supported by the review and results of the following four key objectives: 1) detection of aging effects, 2) timeliness of

corrective actions, 3) review of operating experience, and 4) conformance with license renewal commitments and documentation.

The review concluded that the NMP1 Fatigue Monitoring aging management program satisfactorily met all of the objectives. The following recommendations were completed to further improve program performance: 1) vendor training to improve the program owner's use of the SI:FatiguePro™ software tools and 2) documenting of additional dispositions of Fatigue Monitoring program performance operating experience.

This operating experience provides objective evidence that the Fatigue Monitoring program is being effectively implemented to monitor components for fatigue usage during the first period of extended operation, and continued implementation of the Fatigue Monitoring program will assure that the monitored components will continue to perform their intended functions during the subsequent period of extended operation.

2. In 2024, the most current NMP1 annual cycle and fatigue monitoring program update was completed and documented using SI:FatiguePro™.

In this update, logged plant data was analyzed from SI:FatiguePro™, and transients were reviewed to verify that no erroneous or spurious events occurred. In addition, manual events were added to ensure that all fatigue usage from initial plant startup up to the current date are loaded in SI:FatiguePro™. The environmental fatigue multiplier (F_{en}) was verified in accordance with station procedures and included in the analysis.

All applicable Fatigue Monitoring locations were analyzed to determine the 60-year fatigue usage projections. All Fatigue Monitoring locations were calculated to be within the allowable usage alert limit and in conformance with the corporate guidance.

This example provides objective evidence that the Fatigue Monitoring program effectively monitors plant transients and cumulative usage, utilizes the corrective action program as required, and results in evaluations to demonstrate that cumulative usage will continue to meet acceptance criteria for the life of the unit.

3. In 2024, a new project was initiated to update and improve the Fatigue Monitoring program in support of subsequent license renewal activities and plant-specific NMP1 operating experience reviews. These updates included: 1) new projections of transient cycles and fatigue up to 80 years of operation, 2) fatigue analysis calculation revisions, and 3) an upgrade of the SI:FatiguePro™ software from Version 3 to Version 4.0. Some of the Fatigue Monitoring program updates included:
 - As part of the NMP1 operating experience review, a new transient was evaluated and added to the fatigue analysis calculations and environmentally assisted fatigue calculations for the "Loss of RWCU" transient. The torus shell was also evaluated for 80 years and included for monitoring in SI:FatiguePro™.

- The SI:FatiguePro™ software was upgraded from Version 3 to Version 4.0, and a software verification and validation was completed. This new version of the software automatically calculates and updates the environmental factor.
- The stress-based fatigue module was updated for the feedwater nozzle safe end and feedwater nozzle blend radius, utilizing the six components of stress methodology.

These examples provide objective evidence that the Fatigue Monitoring aging management program effectively updates and improves program procedures and software to more effectively monitor cumulative fatigue usage.

The operating experience relative to the Fatigue Monitoring aging management program did not identify an adverse trend in performance. Periodic assessments of the Fatigue Monitoring aging management program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Fatigue Monitoring aging management program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing Fatigue Monitoring program provides reasonable assurance that aging effects are adequately managed such that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.3.1.2 Neutron Fluence Monitoring

Program Description

The Neutron Fluence Monitoring aging management program is an existing condition monitoring program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor pressure vessel (RPV) and reactor vessel internal (RVI) components to ensure that applicable reactor pressure vessel neutron embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessment for reactor internal components will remain within their applicable limits. The program manages loss of fracture toughness due to neutron irradiation embrittlement. The components evaluated by these analyses are the reactor pressure vessel shell, welds, and nozzles in the beltline and extended beltline region and RVI components subject to reactor coolant and neutron flux environment which are fabricated from carbon or low alloy steel with stainless steel cladding, stainless steel, and nickel alloy materials.

The program has two aspects, one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB).

Monitoring is performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in NRC-approved reports. For fluence monitoring activities that apply to the beltline region of the reactor pressure vessel, the calculational methods are performed in a manner that is consistent with Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001. The methods used to identify materials within the extended beltline region and RVI components are also consistent with NRC-approved methodology in RG 1.190.

The methods and assumptions for determining RPV neutron fluence for the beltline region are consistent with RG 1.190. The methods and assumptions used for the original beltline region are considered appropriate for the beltline region that has been extended to encompass materials projected to experience fluence in excess of 1×10^{17} n/cm² ($E > 1$ MeV) at 67 EFPY. There are three additional RPV plates and one additional weld added to the extended beltline of Unit 1 at 67 EFPY. The NRC-approved MP Machinery & Testing (MPM) discrete ordinates transfer (DORT) methodology utilizes representative BWR surveillance capsule measurements to validate calculational fluence analysis.

The determination of RVI component fast neutron fluence values is not governed by regulatory guidance or requirements. The purpose of determining the fast neutron fluence values of RVI components is to identify applicable degradation mechanisms (e.g., irradiated assisted stress corrosion cracking, neutron embrittlement, etc.), crack growth rates, and support for weldability determinations. The method used to determine the RVI component neutron fluence values was the MPM discrete ordinates transfer (DORT) fluence methodology, which was approved by the NRC. The calculated component fluence is compared to conservative criteria to determine if a threshold value was crossed to identify applicable degradation mechanisms (e.g., irradiated assisted stress corrosion cracking, neutron embrittlement, etc.), to

determine crack growth rates, and support weldability determinations. Ongoing inspections of the RVI components for age-related degradation due to neutron irradiation are also performed in accordance with the BWR Vessel Internals (B.2.1.7) program.

The Neutron Fluence Monitoring program results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for reactor pressure vessel components. This includes but is not limited to the neutron fluence inputs for the reactor pressure vessel upper-shelf energy analyses (or equivalent margin analyses, as applicable to the CLB) and pressure-temperature limits analyses that are required to be performed in accordance with 10 CFR Part 50, Appendix G requirements. Comparisons to the neutron fluence inputs for other analyses include those for Upper Shelf Energy (USE) analyses (A.4.2.2), Adjusted Reference Temperature (ART) analyses (A.4.2.3), RPV Pressure-Temperature (P-T) limits (A.4.2.4), mean RT_{NDT} and probability of failure analyses for the RPV circumferential and axial shell welds (A.4.2.5 and A.4.2.6), core shroud repair stabilizer assembly bracket preload relaxation analysis (A.4.2.7), and aging effect assessments for the reactor internals that are induced by neutron irradiation exposure mechanisms. Plant issues or conditions resulting in non-compliance with the requirements of 10 CFR Part 50, Appendix G or 10 CFR Part 50, Appendix H are entered into the corrective action program. If the neutron fluence assumptions in RPV analyses or augmented inspection bases for RVI components are projected to be exceeded, corrective actions can include updating the analyses for the RPV components or assessing the need to revise the augmented inspection bases for RVI components.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the NMP1 Reactor Vessel Material Surveillance (B.2.1.19) program provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. The NMP1 SLR Reactor Vessel Material Surveillance aging management program will rely on the BWRVIP ISP host site (Peach Bottom Unit 3) to withdraw representative surveillance capsules during the subsequent period of extended operation per the approved schedule of BWRVIP-321-R1-A, "Plan for Extension of the BWR Integrated Surveillance Program (ISP) Through the Second License Renewal (SLR)", Appendix F, with a neutron fluence between one and two times the projected peak vessel neutron fluence that would be found at the end of the subsequent period of extended operation. Specific specimens representing NMP1 materials will then be tested. The peak reactor vessel neutron fluence of interest at the end of the subsequent period of extended operation addresses the time-limited aging analyses (TLAAs) described in the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR), Section 4.2.2, for Upper-Shelf Energy (USE), Pressure Temperature Limits, Elimination of Boiling Water Reactor Circumferential Weld Inspection, and Boiling Water Reactor Axial Welds.

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 and 10 CFR 50.55a.

The Neutron Fluence Monitoring program is implemented in accordance with procedures that are common across Constellation and is considered a fleet program.

The program requirements are applicable to all Constellation plants. The equivalent Neutron Fluence Monitoring program for Peach Bottom Atomic Power Station has been previously evaluated by the NRC, as documented in the Safety Evaluation Report Related to the Subsequent License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3 Docket Nos. 50-277 and 50-278 (ADAMS Accession Number ML20044D902). Based on this evaluation, the NRC determined that the Neutron Fluence Monitoring program will adequately manage the effects of aging such that intended function(s) are maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3).

NUREG-2191 Consistency

The Neutron Fluence Monitoring aging management program is consistent with the ten elements of aging management program X.M2, "Neutron Fluence Monitoring," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Neutron Fluence Monitoring program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2025, an aging management program assessment was performed of activities associated with the Neutron Fluence Monitoring program in support of preparing the license renewal application for subsequent license renewal. The purpose of the aging management program effectiveness review was to verify that the existing activities associated with the Neutron Fluence Monitoring program are being effectively implemented during the first period of extended operation. The objective of the Neutron Fluence Monitoring program is to manage the loss of fracture toughness as a result of neutron irradiation embrittlement of the reactor vessel and reactor vessel internals.

Key program activities from 2009 to present were reviewed. Key activities of the program that were reviewed included program updates resulting from plant modifications, such as fuel transitions. Starting from the 2011 refueling outage, NMP1 transitioned from GE11 fuel to GNF2 fuel. To account for increased fluence values due to updated cycle calculations and the GNF2 fuel introduction, the adjusted reference temperature (ART) calculations were revised. As a result of revised ART values, the P-T curves for 36 EFPY and 46 EFPY were updated and the 36 EFPY curves were implemented at NMP1. The GNF2 transition was also accounted for in the top guide fracture mechanics flaw evaluation. It was determined that there was no decrease in fracture toughness or increase in crack growth rate for any of the top guide flaws which were previously evaluated.

Therefore, the existing top guide fracture mechanics evaluation remained bounding, despite the increased fluence values. The reload core design for cycle 23 included an increase in enrichment for the upper and lower sections of the fuel bundles, which affected the core loading design. Due to the potential of affecting the peak vessel fluence used to derive the 46 EFPY P-T curves, an engineering evaluation was performed to provide the technical basis for ensuring the 46 EFPY P-T curves remained conservative. The evaluation found that the 46 EFPY curves could be used until the end of cycle 25 (March 2023). In 2023, the reactor vessel fluence calculation was updated to reflect the as operated fluence through cycle 25 for the RPV, core shroud/top guide horizontal and vertical welds, and grid beam. Based on the updated calculations, it was determined that the existing 46 EFPY P-T curves could continue to be used until the end of cycle 28 (March 2029).

This operating experience example provides objective evidence that aging management activities associated with the Neutron Fluence Monitoring program are being effectively performed during the first period of extended operation. This example provides objective evidence that the implementation of the Neutron Fluence Monitoring aging management program, with the enhancement, will effectively manage aging effects attributable to neutron fluence during the subsequent period of extended operation.

2. Original plant licensed fluence calculations were performed with an assumed 40-year (32 EFPY) operating period. To support operation during the first period of extended operation, calculations for RPV end-of-life fluence were completed for a 60-year (46 EFPY) operating period utilizing the MPM fluence calculation methodology. Analyses were performed that use the calculated fluence results to address upper-shelf energy, P-T limit curves, RPV circumferential weld examination relief, and RPV axial weld failure probability. The updated RPV P-T limit curves for 46 EFPY were incorporated into the Pressure-Temperature Limits Report prior to the end of the initial operating license term for NMP1. In 2025, an updated Pressure-Temperature (P-T) curve basis report was developed for an 80-year (67 EFPY) operating period. The updated P-T curve basis report was established to the requirements of 10 CFR 50, Appendix G to ensure that brittle fracture of the reactor vessel is prevented by accounting for irradiation embrittlement effects. The results of the MPM two-dimensional discrete ordinates transfer (DORT) code were synthesized to provide a three-dimensional flux profile at the shroud, vessel, and other structures. Calculations for welds and structures above the active fuel region were performed using a three dimensional discrete ordinance transport (TORT) code. Based on the MPM fluence evaluations, and in accordance with RG1.99, the ART and ΔRT_{NDT} values were developed for all RPV plates, welds, and nozzles by Structural Integrity & Associates (SIA). The P-T curves were updated by SIA using the methods documented in the Boiling Water Owner's Group (BWROG) Licensing Topical Reports (LTRs), "Pressure Temperature Limits Report Methodology for Boiling Water Reactors," (ADAMS Accession No. ML13277A557) and "Linear Elastic Fracture Mechanics Evaluation of General Electric Boiling Water Reactor Water Level Instrument Nozzles for Pressure-Temperature Curve Evaluations" (ADAMS Accession No. ML13183A017). The updated RPV P-T limit curves for 67 EFPY will be incorporated into the Pressure-Temperature Limits Report prior to the end of the first period of extended operation for NMP1.

This operating experience example provides objective evidence that the analyses that use neutron fluence as an input are reviewed and updated, as required.

3. Industry operating experience identified that during preparation of fluence predictions to support development of revised P-T limits for the period of extended operation at another nuclear facility, it was discovered that the fluence assumptions for the current analysis were non-conservative due to a legacy error in the model and lack of margin in the extrapolation of fluence values. This resulted in the fluence assumptions for the current analysis being reached approximately two years earlier than expected, requiring the P-T limits in Technical Specifications to be declared non-conservative, requiring implementation of more restrictive administrative limits. The legacy error was discovered prior to the actual P-T limits for the RPV being exceeded.

Review of this issue resulted in revision of the Constellation fleet implementing procedure for the Neutron Fluence Monitoring program to ensure that any change to core design or power distributions are reconciled with the current licensing basis pressure-temperature limit applicability date in terms of EFPY.

This operating experience example provides objective evidence of effective use of industry operating experience to demonstrate the significance of analyses associated with RPV embrittlement and effective implementation of human performance tools to ensure technical adequacy.

4. In support of the reactor vessel material surveillance program, NMP1 withdrew and tested three capsules. Capsule A at 30 degrees was removed at the end of cycle 5 (5.82 EFPY) and Capsule C at 300 degrees was removed at a shutdown during cycle 7 (7.98 EFPY). After each removal, the pressure-temperature curves were evaluated and updated as required. These capsules were then re-encapsulated and reinserted at the beginning of cycle 8 at an accelerated position of 4.42 inches from the vessel wall. The reinserted capsules are indicated with a prime after the original capsule letter. Capsule A' contains untested specimens, reconstituted specimens, and miniature tensile specimens machined from broken ends of tested specimens, all of which were machined from materials in the original Capsule A. Therefore, the specimens in Capsule A' have approximately the same exposure. Capsule C' contains reconstituted specimens and miniature tensile specimens machined from broken ends of tested specimens from Capsule C. Additional unirradiated specimens were also added to Capsule C'. Capsule B at 210 degrees was removed at the end of cycle 12 (16.76 EFPY). The pressure-temperature curves were once again evaluated and updated as required. Capsule A' was found dislodged from the vessel bracket in 2015 and removed from the vessel. A corrective action program issue report was written, and the NRC/ISP were notified of the dislodged capsule and the decision to not re-insert the capsule. NMP1 is currently participating in an NRC-approved ISP which covers the first period of extended operation. Capsules A' and B are stored in the SFP and Capsule C' is recognized as a standby capsule for the ISP and remains in the reactor. In the ISP, two capsules containing representative weld heat 51912 have been tested, but do not bound the projected 80-year 1/4T fluence for the NMP1 target weld heat 1248. An ISP(E) capsule is projected to be tested in 2027. Three capsules containing representative plate heat C1079-1 have been tested. No previously

tested surveillance capsules bound the projected 80-year 1/4T fluence for the NMP1 target plate heat P2076, and no further capsules are due to be tested during the license renewal period. For the subsequent period of extended operation, the NMP1 Reactor Vessel Material Surveillance aging management program will rely on the Peach Bottom Unit 3 host site to withdraw a surveillance capsule per the approved schedule in BWRVIP-321 Revision 1-A, Appendix F, with a neutron fluence for the applicable specimens to be between one and two times the projected peak vessel neutron fluence that would be found at the end of the subsequent period of extended operation. Specific specimens representing NMP1 materials will then be tested.

This operating experience provides objective evidence that the existing Reactor Vessel Material Surveillance (B.2.1.19) program adequately monitors the loss of fracture toughness of the reactor vessel beltline materials due to neutron irradiation embrittlement. In addition, this example also demonstrates that the corrective action program is used effectively to monitor and evaluate conditions adverse to quality.

The operating experience relative to the Neutron Fluence Monitoring program did not identify an adverse trend in performance. The program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Neutron Fluence Monitoring program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The existing Neutron Fluence Monitoring program provides reasonable assurance that the loss of fracture toughness aging effect is adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.3.1.3 Environmental Qualification of Electric Equipment

Program Description

The Environmental Qualification of Electric Equipment aging management program is an existing program that manages the aging of electrical equipment within the scope of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants." The program includes certain electric equipment composed of various polymeric and metallic materials that are important to safety. This electrical equipment could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line break, or post LOCA environment. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ. Age sensitive mechanical components within the boundary of the electrical equipment such as gaskets, seals, or O-rings are included in the qualification when they are relied upon to ensure functional capability of the electrical equipment during or following exposure to harsh environmental accident conditions.

For equipment located in a harsh environment, the objective of EQ is to demonstrate with reasonable assurance that electric equipment important to safety, for which a qualified life has been established, can perform its safety function(s) without experiencing common cause failures before, during, or after applicable design basis events. 10 CFR 50.49 defines the scope of equipment to be included in an EQ program, requires the preparation and maintenance of a list of in-scope equipment, and requires the preparation and maintenance of a qualification file that contains the qualification report. A qualified life is determined for equipment within the scope of the program and appropriate mitigative actions such as replacement, refurbishment, or reanalysis are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded.

An adverse localized environment may increase the rate of aging or have an adverse effect on the basis for equipment qualification. An adverse localized environment is an environment that exceeds the most limiting qualified condition for temperature or radiation of the component material. The program will be enhanced to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first inspections for subsequent license renewal will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Environmental Qualification of Electric Equipment aging management program will be consistent with the ten elements of aging management program X.E1, "Environmental Qualification of Electric Equipment," specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

In the elements identified below, the Environmental Qualification of Electric Equipment program will be enhanced to:

1. Visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic inspection will be performed prior to the subsequent period of extended operation. **Program Element Affected: Detection of Aging Effects (Element 4)**

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are required to be completed prior to the subsequent period of extended operation will be completed no later than the last refueling outage prior to the subsequent period of extended operation.

Operating Experience

The following examples of operating experience provide objective evidence that the Environmental Qualification of Electric Equipment program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In September 2025, an aging management program effectiveness review was performed on the Environmental Qualification (EQ) of Electric Equipment aging management program. The purpose of the review was to verify that the existing EQ program activities were being effectively implemented in the initial period of extended operation. The review included verification that detection of aging effects, if identified, had occurred prior to loss of intended function. Corrective actions were reviewed, including cause evaluation and prevention of reoccurrence, to verify they were timely. Operating experience was reviewed to confirm it was used to inform the aging management program if applicable. License renewal commitments were reviewed to ensure they were properly documented and maintained.

The aging management program effectiveness review concluded that the EQ program is effectively managing the aging effects of EQ components during the initial period of extended operation. No loss of function of any components in the scope of the EQ program due to aging mechanisms was identified during the review. Three issue reports were generated to document findings from the effectiveness review. One issue report was proactively generated to track actions relating to subsequent license renewal and qualified life extension to 80 years. Two issue reports were generated to identify EQ classification discrepancies in the plant database. Updates to correct the discrepancies in the plant database have been completed.

This operating experience example provides objective evidence that program effectiveness reviews of the EQ program are performed to ensure continuous improvement in program implementation. This operating experience also provides objective evidence that the EQ program has been effective in managing aging effects during the initial period of extended operation. This aging management program effectiveness review did not identify any areas that need to be improved to maintain effective performance of the program.

2. On November 20, 2015, NRC Information Notice 2015-12, “Unaccounted for Error Terms Associated with the Irradiation Testing and Environmental Qualification of Important-to-Safety Components,” was issued. The Information Notice informed the industry that in June 2014, a radiation processing vendor notified customers of a potential Part 21 Notice arising from a 10 CFR Part 50 inspection by the NRC of the radiation processing performed by the vendor at its facility. The NRC identified that the vendor had failed to ensure that the measuring and testing system used to determine the applied radiation dose to the components being tested was properly controlled.

The NRC recommended a review of all EQ binders for a qualified component that had irradiation testing performed by the vendor since 1987 be conducted to ensure a) the existing radiation margin is greater than the uncertainties indicated by the vendor based on the testing location and b) EQ documentation be revised to indicate the revised radiation margin based on the new uncertainty.

This information notice was evaluated by NMP1 as part of the station’s operating experience review process. NMP1 performed a review of EQ binders that were potentially impacted by this issue. More than 70 EQ binders were identified as being impacted and all but three still met the 10 percent margin recommendation between the plant dose and re-adjusted test dose. The three impacted EQ binders were revised to incorporate the new qualified radiation values and address the reduction in margin.

This operating experience provides objective evidence that industry operating experience is evaluated and used to enhance the Environmental Qualification program.

3. In 2014, the station identified four EQ solenoid valves that did not have preventive maintenance tasks established for periodic replacement. The four emergency condenser solenoid valves were last replaced on April 23, 2005, and had a qualified life of 6.41 years identified in their respective EQ binder. At the time of identification, the solenoid valves had not been replaced since installation on April 23, 2005, and were beyond their established qualified lives.

An engineering evaluation was performed that identified conservatism in the existing aging analysis. Using an alternate aging methodology and identified conservatism, qualified life of the solenoid valves was extended to 10 years. The solenoid valves were replaced in 2015, and preventive maintenance tasks were established to ensure replacement prior to exceeding their qualified lives.

This operating experience provides objective evidence that corrective actions were implemented in accordance with the NMP1 corrective action program to address EQ components found to be outside the bounds of their qualification basis. Action was taken to re-evaluate the components’ qualified lives, replace the affected components, and establish preventive maintenance tasks to prevent reoccurrence.

The operating experience relative to the Environmental Qualification of Electric Equipment program did not identify an adverse trend in performance. Periodic assessments of the program are performed to identify the areas that need improvement to maintain effective performance of the program. The program is

informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that continued implementation of the Environmental Qualification of Electric Equipment program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Environmental Qualification of Electric Equipment program will provide reasonable assurance that the aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

APPENDIX C

RESPONSE TO BWRVIP LICENSE RENEWAL APPLICANT ACTION ITEMS

Of the BWRVIP reports credited within Nine Mile Point Nuclear Station, Unit 1 (NMP1) license renewal aging management programs, the following include NRC safety evaluation reports (SERs) with applicant action items (AAls) for license renewal applicants:

- BWRVIP-18, Revision 2-A, “BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines”
- BWRVIP-25, Revision 1-A, “BWR Core Plate Inspection and Flaw Evaluation Guidelines”
- BWRVIP-26-A, “BWR Top Guide Inspection and Flaw Evaluation Guidelines”
- BWRVIP-27-A, “BWR Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines” (Credited in BWR Penetrations program)
- BWRVIP-38, “BWR Shroud Support Inspection and Flaw Evaluation Guidelines”
- BWRVIP-47-A, “BWR Lower Plenum Inspection and Flaw Evaluation Guidelines” (Credited in BWR Penetrations program)
- BWRVIP-48-A, “BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines” (Credited in BWR Vessel ID Attachment Weld program)
- BWRVIP-49-A, “BWR Instrument Penetration Inspection and Flaw Evaluation Guidelines” (Credited in BWR Penetrations program)
- BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guideline for License Renewal”
- BWRVIP-76, Revision 1-A, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines”
- BWRVIP-139, Revision 1-A, “Steam Dryer Inspection and Flaw Evaluation Guidelines”
- BWRVIP-315-A, “Reactor Internals Aging Management Evaluation for Extended Operations”

License renewal applicant action items identified in the corresponding SERs for each of the above BWRVIP reports are addressed in the following tables. BWRVIP reports without SERs for license renewal do not have action items and are therefore not included in the tables. License renewal action items that are applicable to multiple BWRVIP reports are combined in the tables below and addressed together.

The BWRVIP-315-A safety evaluation was issued in October 2023. The safety evaluation does not contain license renewal applicant action items but does contain five “Conditions” and seven “Limitations” that are addressed in the tables.

Common Action Items from BWRVIP-18 Revision 2-A, -25 Revision 1-A, -26-A, -27-A, -38, -47-A, -48-A, -49-A, -74-A, -76 Revision 1-A	
Action Item Description	NMP1 Response
BWRVIP-All (AAI 1) The license renewal applicant is to verify that its plant is bounded by the report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP reports to manage the effects of aging of subject components during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within these BWRVIP reports described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the components or other information presented in the reports, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWRVIP reports applicable to NMP1 have been reviewed and NMP1 aging management programs have been verified to be bounded by the reports. Additionally, NMP1 is committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the subsequent period of extended operation. These commitments are included in SLRA Appendix A, Section A.5. If, upon review of a BWRVIP approved guideline, it is determined that known deviations to full compliance are warranted, the NRC will be notified of the deviation within 45 days of the receipt of the NRC final approval of the guideline. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50, Appendix B..
BWRVIP-All (AAI 2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contains a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the programs and activities specified as necessary in the applicable BWRVIP reports are summarily described in the FSAR supplement.	The UFSAR supplements are included in SLRA Appendix A. The UFSAR supplements include a summary description of the programs and activities specified as necessary for managing the effects of aging per the BWRVIP reports.

Common Action Items from BWRVIP-18 Revision 2-A, -25 Revision 1-A, -26-A, -27-A, -38, -47-A, -48-A, -49-A, -74-A, -76 Revision 1-A	
Action Item Description	NMP1 Response
BWRVIP-AII (AAI 3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The applicable BWRVIP reports may state that there are no generic changes or additions to technical specifications associated with the report as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the inspection strategy described in the reports does not conflict with or result in any changes to their technical specifications. If technical specification changes or additions do result, then the applicant must ensure that those changes are included in its application for license renewal.	There are no changes to technical specifications needed to meet the requirements of the BWRVIP reports during the subsequent period of extended operation. Reference SLRA Appendix D.

Additional Action Items	
BWRVIP-18, Revision 2-A, “Core Spray Internals Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-18, Revision 2-A (AAI 4) Applicants referencing the BWRVIP-18 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components.	Cumulative fatigue damage is a potential TLAA issue identified for core spray system piping and components internal to the reactor vessel. TLAA is used to manage cumulative fatigue damage for the core spray piping and components as discussed in SLRA Sections 4.3.1 and 4.3.2.
BWRVIP-25, Revision 1-A, “Core Plate Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-25, Revision 1-A (AAI 4) Due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.	The NMP1 core plate was modified in 1995 to install four core plate wedges. A plant-specific evaluation performed in accordance with BWRVIP-25, Revision 1-A determined that evaluation of stress relaxation and loss of preload on the rim hold-down bolts is not required. Therefore, there cannot be a TLAA associated with stress relaxation on the rim hold-down bolts.
BWRVIP-25, Revision 1-A (AAI 5) Until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspections of the rim hold-down bolts.	The NMP1 core plate was modified to install four core plate wedges, therefore inspections of the rim hold-down bolts are not required.

BWRVIP-26-A, “Top Guide Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-26-A (AAI 4) Due to IASCC susceptibility of the subject safety-related components, applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue.	The fluence evaluation for reactor internals performed for subsequent license renewal determined that the neutron fluence threshold for IASCC susceptibility has been exceeded, therefore, evaluating the projected accumulated neutron fluence as a potential TLAA is considered not warranted. During the subsequent period of extended operation, the aging of the top guide will be managed by inspections conducted as part of the BWR Vessel Internals (B.2.1.7) program per guidance provided in BWRVIP-26-A and BWRVIP-183-A. The program requires that existing top guide flaws be re-inspected on a periodicity not to exceed six years. Additionally, any new indications are examined in each successive outage until they have stabilized for two consecutive outages. BWRVIP-183-A allows use of EVT-1 or UT for top guide inspections. NMP1 is currently using UT inspections to achieve approximately 100 percent coverage of the top guide grid beam locations, with inspections performed during the 2005, 2015, and 2021 refueling outages. Inspections will continue to be performed as described above during the subsequent period of extended operation.

BWRVIP-27-A, “Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-27-A (AAI 4) Due to the susceptibility of the subject components to fatigue, applicants referencing the BWRVIP-27 report for license renewal should identify and evaluate the projected fatigue cumulative usage factors as a potential TLAA issue.	Cumulative fatigue damage is a potential TLAA issue identified for the SLC system/core plate dP penetration. TLAA is used to manage cumulative fatigue damage for the SLC system/core plate dP penetration as discussed in SLRA Section 4.3.
BWRVIP-47-A, “BWR Lower Plenum Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-47-A (AAI 4) Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue.	Fatigue usage is considered a TLAA for reactor vessel in-core instrumentation penetrations and CRD penetrations. This is addressed in SLRA Sections 4.3.1 and 4.3.2.

BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-74-A (AAI 4) The staff is concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD lines, cause an increase in the concentration of contaminants and cause cracking in the VFLD line. The BWRVIP-74 report does not identify this component as within the scope of the report. However, since the VFLD line is attached to the RPV and provides a pressure boundary function, LR applicants should identify an AMP for the VFLD line.	The vessel flange leak detection (VFLD) nozzles and piping are included in the scope of license renewal. The high pressure seal leak detection nozzle is made from stainless steel and nickel alloy, while the low pressure seal leak detection nozzle is made from carbon steel. For the high pressure seal leak detection nozzle, cracking is managed by the ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) programs. Loss of material for the stainless steel component is managed by the One-Time Inspection (B.2.1.20) and Water Chemistry (B.2.1.2) programs, while loss of material for the nickel alloy component is managed by the Water Chemistry (B.2.1.2) program. For the low pressure seal leak detection nozzle, loss of material is managed by the One-Time Inspection (B.2.1.20) and Water Chemistry (B.2.1.2) programs. The VFLD piping is fabricated from stainless steel. Cracking and loss of material are managed by the One-Time Inspection (B.2.1.20) and Water Chemistry (B.2.1.2) programs.

BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-74-A (AAI 5) LR applicants shall describe how each plant-specific aging management program addresses the following elements: (1) scope of program, (2) preventative actions, (3) parameters monitored and inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	There are no plant-specific aging management programs credited for managing aging of reactor pressure vessel components. Descriptions of the aging management programs credited for managing the reactor pressure vessel are described in Appendix B. These descriptions include any program elements that deviate from the NUREG-2191 program elements, and any enhancements that are required to meet NUREG-2191 requirements.
BWRVIP-74-A (AAI 6) The staff believes inspection by itself is not sufficient to manage cracking. Cracking can be managed by a program that includes inspection and water chemistry. BWRVIP-29 describes a water chemistry program that contains monitoring and control guidelines for BWR water that is acceptable to the staff. BWRVIP-29 is not discussed in the BWRVIP-74 report. Therefore, in addition to the previously discussed BWRVIP reports, LR applicants shall contain water chemistry programs based on monitoring and control guidelines for reactor water chemistry that are contained in BWRVIP-29.	The Water Chemistry (B.2.1.2) aging management program is consistent with the NUREG-2191, Revision 1, XI.M2 program with exceptions, as described in NM1-PBD-AMP-XI.M2, “Water Chemistry,” and meets the requirements of the latest BWRVIP Water Chemistry guidelines to help ensure the long-term integrity of the reactor vessel and internals. Aging management programs that utilize inspections to perform condition monitoring of reactor pressure vessel and internal components also credit the Water Chemistry program to mitigate cracking of reactor vessel components, including the BWR Vessel Internals (B.2.1.7), BWR Vessel ID Attachment Welds (B.2.1.4), BWR Penetrations (B.2.1.6), and BWR Stress Corrosion Cracking (B.2.1.5) programs.

BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-74-A (AAI 7) LR applicants shall identify their vessel surveillance program, which is either an ISP or plant-specific in-vessel surveillance program, applicable to the LR term.	The Reactor Vessel Material Surveillance (B.2.1.19) program describes the surveillance program that is applicable for the subsequent license renewal term. NMP1 is currently participating in an integrated surveillance program (ISP). For the subsequent license renewal, NMP1 will implement the guidance in BWRVIP-321, Revision 1-A, “Plan for Extension of the BWR Integrated Surveillance Program (ISP) Through the Second License Renewal (SLR),” including the alternate withdrawal schedule in Appendix F consistent with the NRC’s approval in ML22290A191.
BWRVIP-74-A (AAI 8) LR applicants should verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternative actions for cases where the estimated fatigue usage is projected to exceed 1.0 will require case-by-case staff review and approval. Further, a LR applicant must address environmental fatigue for the components listed in the BWRVIP-74 report for the LR period.	The Metal Fatigue Analyses associated with the reactor vessel are evaluated as TLAAs in SLRA Section 4.3.2. Fatigue TLAAs are managed by the Fatigue Monitoring (B.3.1.1) program to ensure that cumulative fatigue usage will not exceed 1.0. Environmental fatigue for reactor vessel components is evaluated in SLRA Section 4.3.5.
BWRVIP-74-A (AAI 9) Appendix A to the BWRVIP-74 report indicates that a set of P-T curves should be developed for the heat-up and cool-down operating conditions in the plant at a given EFPY in the LR period.	P-T limit curves will be developed per 10 CFR 50, Appendix G requirements for the subsequent period of extended operation as discussed in SLRA Section 4.2.4.

BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-74-A (AAI 10) To demonstrate that the beltline materials meet the Charpy USE criteria specified in Appendix B of the report, the applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials are less than those specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for their surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2.	Charpy upper-shelf energy (USE) values for the subsequent period of extended operation were determined using methods consistent with RG 1.99, Revision 2. Equivalent Margin Analysis (EMA) is used for all NMP1 beltline and extended beltline materials lacking unirradiated USE values, as NMP1 was designed and fabricated prior to the current Charpy USE requirements going into effect. This is discussed as a TLAA in SLRA Section 4.2.2.
BWRVIP-74-A (AAI 11) To obtain relief from the inservice inspection of the circumferential welds during the LR period, the BWRVIP report indicates each licensee will have to demonstrate that (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the Appendix E for the staff's July 28, 1998, SER, and (2) that they have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER.	At the end of the subsequent license renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the NRC's July 28, 1998, FSER (ML20236V555) and BWRVIP-329-A. Relief from the inservice inspection of the circumferential welds during the subsequent period of extended operation is discussed in SLRA Section 4.2.5.
BWRVIP-74-A (AAI 12) As indicated in the staff's March 7, 2000, letter to Carl Terry, a LR applicant shall monitor axial beltline weld embrittlement. One acceptable method is to determine that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of this FSER.	The Axial Weld Failure Probability Assessment Analyses have been identified as TLAAs, meet the requirements of BWRVIP-329-A, and are discussed in SLRA Section 4.2.6.

BWRVIP-74-A, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-74-A (AAI 13) The Charpy USE, P-T limit, circumferential weld and axial weld RPV integrity evaluations are all dependent upon the neutron fluence. The applicant may perform neutron fluence calculations using staff approved methodology or may submit the methodology for staff review. If the applicant performs the neutron fluence calculation using a methodology previously approved by the staff, the applicant should identify the NRC letter that approved the methodology.	An NRC approved methodology was used to determine fluence during the subsequent period of extended operation, as discussed in SLRA Section 4.2.1.
BWRVIP-74-A (AAI 14) Components that have indications that have been previously analytically evaluated in accordance with sub-section IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period shall be re-evaluated for the 60-year service period corresponding to the LR term.	During the 1999 refueling outage, augmented examinations identified unacceptable flaw indications in one RPV shell weld and one RPV shell to flange weld. During the 2003 refueling outage, UT examinations identified an unacceptable flaw indication in a closure head meridional weld. Structural evaluations of these flaws (performed in accordance with ASME Section XI, Subsection IWB-3600) compared the flaw characteristics to pre-determined acceptability criteria to justify continued operation without repair of the flaw through the original 40 year license term. These indications were re-evaluated and determined to be adequately managed for the 60-year and 80-year service period. These evaluations are discussed in SLRA Section 4.7.

BWRVIP-76, Revision 1-A, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-76, Revision 1-A (AAI 4) The applicant shall reference the NRC staff-approved TRs BWRVIP-14-A, BWRVIP-99 (when approved) and BWRVIP-100-A in their RVI AMP. The applicant shall make a statement in their LRA that the crack growth rate evaluations and fracture toughness values specified in these reports shall be used for cracked core shroud welds that are exposed to the neutron fluence values that are specified in these TRs. The applicant shall confirm that they will incorporate any emerging inspection guidelines developed by the BWRVIP for these welds.	The BWR Vessel Internals (B.2.1.7) program implements BWRVIP-76, Revision 1-A requirements including guidance within BWRVIP-76, Revision 1-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values. The BWR Vessel Internals program includes reference to BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100, Revision 2 for evaluation of crack growth. The current guidance references BWRVIP-14-A and BWRVIP-99-A for crack growth rates and BWRVIP-100, Revision 2 for fracture toughness values. The implementing procedures for the BWR Vessel Internals program include requirements to incorporate guidance from new or revised BWRVIP reports. This ensures that any emerging inspection guidelines developed by the BWRVIP for core shroud welds will be incorporated into the program.

BWRVIP-76, Revision 1-A, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-76, Revision 1-A (AAI 5) LR applicants that have core shrouds with tie rod repairs shall make a statement in their AMP associated with RVI components that they have evaluated the implications of the Hatch Unit 1 tie rod repair cracking on their units and incorporated revised inspection guidelines, if any, developed by the BWRVIP.	NMP1 installed a shroud tie-rod repair during the 1995 refueling outage. Subsequent tie-rod inspections meet the requirements of BWRVIP-76, Revision 1-A and vendor repair design requirements. In response to the tie-rod cracking observed at Hatch Unit 1, NMP1 replaced all existing tie rod upper supports and tie rod nuts during the 2007 refueling outage. A new baseline exam was performed during the refueling outage in 2009. Re-inspection of all four tie-rods and their upper supports was performed during the 2019 refueling outage. No indications of cracking were found. NMP1 will continue inspecting the tie-rod hardware and upper supports per vendor repair design requirements. The potential for cracking of core shroud tie rod subcomponents fabricated from X-750 Inconel material is discussed in SLRA Section 4.7.9.

BWRVIP-76, Revision 1-A, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-76, Revision 1-A (AAI 6) The NRC staff’s guidance in Table IV.B1 of the GALL Report lists two potentially applicable aging effects (i.e., in addition to cracking) for generic BWR reactor vessel internal components (including BWR core shroud and core shroud repair assembly components) that are made from either stainless steel (including CASS) or nickel alloy: (1) loss of material due to pitting and crevice corrosion (Refer to GALL AMR IV.B1-15), and cumulative fatigue damage (Refer to AMR Item IV.B1-14). BWR LR applicants will need to assess their designs to see if the generic guidelines for managing cumulative fatigue damage in GALL AMR item IV.B1-14 and for management of loss of material due to pitting and crevice corrosion in GALL AMR IV.B1-15 are applicable to the design or their core shroud components (including welds) and any core shroud assembly components that have been installed through a design modification of the plant. If these aging effects are applicable to the design of these components as a result of exposing them to a reactor coolant with integrated neutron flux environment, applicants for license renewal will need to: (1) identify the aging effects as aging effects requiring management (AERM) for the core shrouds and for their core shroud assembly components if a repair design modification has been implemented, and (2) identify the specific aging management programs or time-limited aging analyses that will be used to manage these aging effects during the period of extended operation. Refer to License Renewal Applicant Action Item 7) for additional guidance on identifying the AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy.	The core shroud and repair hardware (including welds) are fabricated from stainless steel and nickel alloy material. Cumulative fatigue damage for the core shroud repair and shroud conical support has been identified as a TLAA as discussed in SLRA Section 4.3.6. In addition to cracking, loss of material due to pitting and crevice corrosion and cumulative fatigue damage are identified as aging effects requiring aging management. The BWR Vessel Internals (B.2.1.7) and Water Chemistry (B.2.1.2) programs will be used to manage cracking and loss of material due to pitting and crevice corrosion during the subsequent period of extended operation.

BWRVIP-76, Revision 1-A, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-76, Revision 1-A (AAI 7) For BWR LRAs identification of AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy will need to be addressed on a plant-specific basis that is consistent with the Note format criteria for plant-specific AMR items in the latest NRC-approved version TR NEI 95-10.	The core shroud and tie-rod repair hardware (including welds) are fabricated from stainless steel and nickel alloy material. Therefore, this Action Item does not apply to NMP1.
BWRVIP-76, Revision 1-A (AAI 8) LR applicant shall reference the NRC staff-approved topical reports BWRVIP-99 and BWRVIP-100-A in their RVI components AMP.	The BWR Vessel Internals (B.2.1.7) program implements BWRVIP-76, Revision 1-A requirements including guidance within BWRVIP-76, Revision 1-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values. The current guidance includes letter 2012-074 from Randy Stark, EPRI, BWRVIP Program Manager, to All BWRVIP Committee Members, Superseded “Needed” Guidance Regarding Crack Growth Assumptions, March 22, 2012 for evaluation of crack growth rates in austenitic stainless steel and nickel based alloy components. This guidance is consistent with BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100, Revision 2, as applicable. The implementing procedures for the BWR Vessel Internals program include reference to applicable BWRVIP reports for evaluation of crack growth.

BWRVIP-139, Revision 1-A, “Steam Dryer Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-139, Revision 1-A (AAI 1) Aging Effects and Mechanisms Not Assessed or Managed in TR No. BWRVIP-139, Appendix B–Plant-Specific Design Differences or Operating Experience Considerations The regulation in 10 CFR 54.21(a)(3) requires a license renewal applicant to manage all aging effects that are applicable to those plant components that have been scoped in for license renewal in accordance with 10 CFR 54.4 and have been screened in for an AMR in accordance with 10 CFR 54.21(a)(1). Guidelines for identifying applicable aging effects are given in Section A.1.2.1 of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR, with the current version being Revision 2 of the report), and in TR No. NEI 95-10 (current NRC-endorsed version of the report is Revision 6 of the NEI report). a) BWR applicants for license renewal are requested to perform a review of the CLB and design basis of their facilities to determine whether there are any design differences in their steam dryer designs or steam dryer-related OE that is applicable for their BWR design. Specifically, BWR applicants for license renewal are requested to perform a review of the CLB and design basis of their facilities to determine whether there are any additional aging effects/mechanisms that might be applicable to the designs of their BWR steam dryer assemblies, in addition to those that are mentioned as being applicable aging effects/mechanisms requiring management (AERMs) in BWRVIP-139, Appendix B. b) For those BWR license renewal applicants that identify additional AERMs beyond those listed in BWRVIP-139, Appendix B, the applicants should include applicable GALL-based or plant-specific AMR items in the LRAs that identify the additional aging effects that are applicable to their steam dryer designs, and should identify and justify the AMP or TLAA that will be used to manage those aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3)	a) NMP1 has original plant equipment steam dryers. Inspections of the dryers are performed in accordance with OEM guidance and BWRVIP-139, Revision 1-A guidance. Review of the CLB and design basis determined that loss of preload is an additional aging effects in addition to those that are mentioned in BWRVIP-139, Revision 1-A, Appendix B as being applicable aging effects/mechanisms requiring management, crack initiation and growth and loss of material due to wear or flow induced vibrations. There are no TLAAs associated with the steam dryers. b) Loss of preload for the steam dryer bolted/welded clamp repairs is managed by the BWR Vessel Internals (B.2.1.7) program. Inspections of the steam dryer bolted/welded clamp repairs are performed every 10 years in accordance with BWRVIP-139, Revision 1-A.

BWRVIP-139, Revision 1-A, “Steam Dryer Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-139, Revision 1-A (AAI 2) Referencing of the BWRVIP-139-A Report and Appendix B of the Report in the FSAR, UFSAR, or USAR Supplement For demonstration of the requirement in 10 CFR 54.21(d), BWR license renewal applicants applying the BWRVIP-139 report and Appendix B of the report to manage age-related degradation in their BWR steam dryer assemblies shall describe or reference in the applicable FSAR, UFSAR, or USAR supplement summary description for the AMP how the BWRVIP-139 report and Appendix B of the report will be used to manage aging in the plant’s steam dryer assembly components during the period of extended operation.	UFSAR Supplement, SLRA Appendix A to BWR Vessel Internals (B.2.1.7) program describes the use of applicable BWRVIPs (i.e., BWRVIP-139, Revision 1-A) to manage the aging effects of cracking and loss of material due to wear or flow induced vibration for the steam dryers.

BWRVIP-139, Revision 1-A, “Steam Dryer Inspection and Flaw Evaluation Guidelines”	
Action Item Description	NMP1 Response
BWRVIP-139, Revision 1-A (AAI 3) Identification of Time Limited Aging Analyses License renewal applicants are required by 10 CFR 54.21(c)(1) to identify all analyses in the CLB that conform to the six criteria in 10 CFR 54.3(a) for defining an analysis as a TLAA. For those BWR license renewal applicants that confirm that the CLB includes a steam dryer analysis and the analysis conforms to the definition of TLAA, the applicants shall: - include the TLAA in the LRA in accordance with the requirements in 10 CFR 54.21(c)(1) - demonstrate that the TLAA will be acceptable for the period of extended operation in accordance with one of three criteria for accepting TLAAs in 10 CFR 54.21(c)(1)(i), (ii), or (iii), and - include a FSAR, UFSAR or USAR supplement summary description for the TLAA in the LRA, in accordance with 10 CFR 54.21(d). These bases are consistent with the guidelines for formatting LRAs in NEI 95-10, Revision 6.	No TLAAs were identified for NMP1 steam dryers.

BWRVIP-315-A, “Reactor Internals Aging Management Evaluation for Extended Operations”	
Action Item Description	NMP1 Response
BWRVIP-315-A (Condition 1) Applicants for renewed operating licenses extending beyond 60 years applying Code Case N-889 to calculate IASCC crack growth rate must comply with the conditions in the latest edition of RG 1.147 incorporated by reference in 10 CFR 50.55a.	NMP1 uses Code Case N-889 to calculate IASCC crack growth rate. When Code Case N-889 is used, the calculations comply with the conditions in the latest edition of RG 1.147.
BWRVIP-315-A (Condition 2) Applicants for renewed operating licenses extending beyond 60 years must describe in the application whether the core plate holddown bolt analysis per BWRVIP-25, Appendix I is a TLAA. If so, the applicant must include the analysis as a TLAA in the licensing application.	NMP1 core plates were modified during the refueling outage in 1995 to install four core plate wedges, therefore preload on the rim hold-down bolts is not required. BWRVIP-315-A determined that there are no aging effects requiring management that are impacted by extended operations for the core plate wedges. There are no associated TLAAs. No further actions are required.
BWRVIP-315-A (Condition 3) Applicants for renewed operating licenses extending beyond 60 years must describe and justify in the application plant-specific re-inspection plans for the lower plenum in the application.	Per BWRVIP-47-A, the BWRVIP has determined that removal or dismantling of internal components for the purpose of performing a baseline inspection is not warranted. However, on occasion, NMP1 will have access to the lower plenum due to maintenance activities not related to the inspection recommendation in the guidelines. In such cases, NMP1 will perform a visual inspection of the accessible portion of the lower plenum to the extent practical. Results of the inspection would be reported to the BWRVIP and would be compiled into the inspection summary that is forwarded to the NRC as required by BWRVIP-47-A, Section 3.2.5. Although it is uncommon to have access to the lower plenum, there is one path that could be accessible: through the removal of

BWRVIP-315-A, “Reactor Internals Aging Management Evaluation for Extended Operations”	
Action Item Description	NMP1 Response
BWRVIP-315-A (Condition 3 - continued)	one or more control rod guide tubes. If one or more control rod guide tubes were removed, then accessible components in the vicinity, adjacent to that core location, could potentially be examined, such as any adjacent control rod drive stub tube and housing welds and any adjacent instrument housing welds. This inspection plan is justified based on the inspections performed to date and the safety assessment performed in BWRVIP-06, Revision 1-A. For CRGTs, BWRVIP-47-A recommends performing baseline VT-3 visual inspections of the guide tube to alignment lug weld (CRGT-1) and the guide tube circumferential welds (CRGT-2 and CRGT-3). These inspections were performed at NMP1 during the refueling outages in 1999, 2001, 2007, 2011, 2013, 2015, 2019, and 2021. Although re-inspection of CRGT-1 welds is not currently required, the orificed fuel supports are removed and installed during routine control rod blade replacement activities at which time the CRGT-1 weld would be observed. Also, failure of the CRGT-1 weld was determined to have no safety consequence as evaluated in BWRVIP-47-A and BWRVIP-06, Revision 1-A. Based on the verification of the alignment lug during control rod blade replacement activities and no safety consequences associated with a failed alignment lug, supplemental inspections, or enhancements to the current BWRVIP guidance are not necessary. For orificed fuel support pieces, these components are observed during routine control rod blade replacement which occurs during refuel outage maintenance. Abnormalities or cracks would likely be identified at that time. During normal plant

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BWRVIP-315-A (Condition 3 - continued)	operation, the orificed fuel support castings are in compression and tensile stresses are not present to initiate a crack. The orificed fuel support castings are cast from ferritic – austenitic duplex stainless steel which is highly resistant to IGSCC. An assessment documented in BWRVIP-06, Revision 1-A, Safety Assessment of BWR Reactor Internals, concluded that the orificed fuel support castings are highly resistant to impairment by cracking due to the one piece fabrication. Since the orificed fuel support pieces are routinely observed during routine control rod blade replacements and cracking has not been observed, no short-term (or long-term) action is required, and supplemental inspections or enhancements to the BWRVIP guidance are not considered necessary. For SLC/core plate DP, BWRVIP-27-A provides the inspection recommendations which state that even without detection of cracking of the SLC/core plate DP system piping, the system would function adequately when initiated as long as the boron is injected into the bottom head. Cracking of the lower plenum SLC/core plate DP piping would not prevent boron injection into the lower head. Therefore, the focus of the evaluations in BWRVIP-27-A is on the region where the SLC/core plate DP system housing or nozzle penetrates the vessel bottom head. The BWR Penetrations (B.2.1.6) aging management program manages cracking of the vessel penetration/nozzle and lower plenum inspections are not required. During each refueling outage, a visual inspection (VT-2) of the BWR instrumentation penetrations, CRD housing and ICHM penetrations, and SLC/core plate DP system nozzle is performed during the reactor coolant pressure boundary system

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BWRVIP-315-A (Condition 3 - continued)	leakage test. In addition, hydrogen water chemistry treatment is used to mitigate the potential for IGSCC in all lower plenum components. Inspection of lower plenum components when accessible, as well as the VT-2 of the bottom head penetrations every refuel outage, provides an acceptable plan for identification of degradation during the subsequent period of extended operation. Should any new or revised inspection recommendations be published, the new guidance is required to be implemented in accordance with BWRVIP-94, Revision 4 and NEI 03-08, “Guideline for the Management of Material Issues.” As described in SLRA Section 4.3, a TLAA has been performed to evaluate cumulative fatigue damage of the reactor vessel CRD penetrations, and SLC/core plate DP penetration.
BWRVIP-315-A (Condition 4) Applicants for renewed operating licenses extending beyond 60 years must justify applicability for non-RAMA-based, plant-specific fluence evaluations. Alternatively, the BWRVIP may address the generic qualification to evaluate RVI component fluence for each fluence methodology in use at operating BWRs.	NMP1 has obtained reactor vessel internals (RVI) fluence projections for various internal components from MP Machinery & Testing (MPM). The NMP1 components evaluated are listed below: 1. Core shroud 2. Top guide 3. Core plate 4. Core spray sparger nozzle elbows 5. CRGT welds 1, 2, and 3 6. Core shroud repair tie-rods 7. Core shroud vertical weld clamps (V9/10) 8. Orificed fuel support (OFS) The NMP1 fluence projections for the RVI components were calculated using the Discrete Ordinates Transfer (TORT/DORT) methodology, as justified in SLRA Section 4.2.1

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BWRVIP-315-A (Condition 5) Applicants for renewed operating licenses extending beyond 60 years must describe in the application how they meet the seven BWRVIP-defined limitations listed in BWRVIP-315-A, Section 4.5.1. <u>Limitation 1 – Core Plate Holddown Bolting Evaluation:</u> Core plate holddown bolting is subject to a plant-specific evaluation or to augmented inspections if the criteria for use of the generic evaluation documented in BWRVIP-25, Rev. 1 cannot be met. BWRVIP-25, Rev. 1 provides guidance for performing such a plant-specific evaluation. The relevant limitation applicable to extended operation is core plate holddown bolt fluence. See Section 4.3.2 for additional discussion. This limitation is already appropriately identified and described within BWRVIP-25, Rev. 1 (See BWRVIP-25, Rev. 1, Appendix I). No revision to BWRVIP-25, Rev. 1 is needed to address extended operations. <u>Limitation 2 – CRGT Aging Management:</u> BWRVIP-47-A provides for a set of baseline examinations of CRGTs. Section 3.2.2 of BWRVIP-47-A states: <i>Currently no additional inspections are recommended beyond the baseline inspections described in Section 3.2.2, and scope expansion and follow-on inspections deemed necessary in the event flaws are found as given in Section 3.2.3. Baseline inspection results will be reviewed by the BWRVIP and, if deemed necessary, reinspection recommendations will be</i>	NMP1 core plates were modified during the refueling outage in 1995 to install four wedge assemblies that replace the lateral support function of the core plate holddown bolts. Therefore, consistent with the conclusions presented in BWRVIP-25, Revision 1-A, loss of preload of the rim hold-down bolts is not an aging effect requiring management and evaluation of core plate holddown bolt preload is not required. BWRVIP-47-A recommends performing baseline inspections of the guide tube to alignment lug weld (CRGT-1) and the guide tube circumferential welds (CRGT-2 and CRGT-3). These inspections were performed at NMP1 during the refueling outages 1999, 2001, 2007, 2011, 2013, 2015, 2019, and 2021. The industry baseline inspection results are under evaluation and future inspection recommendations are pending. Any new or revised inspection recommendations in BWRVIP-47 are required to be implemented in accordance with BWRVIP-94, Revision 4, “BWR Vessel and Internals Project, Program

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<i>developed at a later date and provided to the NRC.</i> Since the BWRVIP has not yet completed an evaluation to assess reinspection needs in a manner that considers extended operations, until such time as a new version of BWRVIP-47 is developed, owners submitting an application for operation beyond 60 years (e.g., an SLRA in the U.S.) should either commit to implementing a future version of BWRVIP-47 that addresses extended operations or propose a set of plant-specific activities to manage age-related degradation of CRGTs. Given that changes to BWRVIP-47 to address extended operations will be dependent on the outcome of the evaluation described above, proposed changes to address this issue cannot be proposed at this time. <u>Limitation 3 – CASS Embrittlement:</u> Jet pump and LPCI coupling CASS components subjected to fluence exceeding 6×10^{20} n/cm² ($E > 1.0$ MeV) must be evaluated on a plant-specific basis or be included in a plant-specific aging management program. This limitation is based on the fluence criterion contained in BWRVIP-234-A. BWRVIP I&E guidelines affected include BWRVIP-41 and BWRVIP-42. See Sections 4.3.8 and 4.3.10 for additional discussion. Appropriate changes to BWRVIP-41 to identify this limitation are included in Appendix B, Section B.1. Appropriate changes to BWRVIP-42 to identify and describe this limitation are included in Appendix B, Section B.2.	Implementation Guide,” and NEI 03-08, “Guideline for the Management of Material Issues.” Future revisions of BWRVIP-47 that address NMP1 extended operations will be implemented as applicable. The NMP1 reactor internals design does not include jet pump assemblies or a LPCI coupling.

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<u>Limitation 4 – Jet Pump Large Diameter Weld Scope Expansion Exemption:</u> A scope expansion exemption is provided within BWRVIP-41, Rev. 4-A for large diameter jet pump diffuser, adapter, and lower ring welds (DF-1, DF-2, DF-3, AD-1, AD-2, and AD-3a,b) inspected by UT. As currently included in BWRVIP-41, Rev. 4-A, the exemption is based on an assumption of a 60-year service life. As discussed in Section 4.3.8, this exemption will be revised to be interval-based (24-year intervals allowed) rather than based on a 60-year service life. Until such time as BWRVIP-41 is revised, use of the scope expansion exemption allowance should be limited to plants not intending to operate beyond 60 years. Appropriate changes to BWRVIP-41 that are planned to eliminate this limitation are described in Appendix B, Section B.1.3.	The NMP1 reactor internals design does not include jet pump assemblies.
<u>Limitation 5 – Jet Pump Holddown Beam IASCC:</u> Jet pump holddown beams subject to neutron fluence exceeding 5×10^{20} n/cm² (E > 1.0 MeV) in the BB-2 region require plant-specific evaluation to address IASCC concerns. This limitation is applicable to BWRVIP-41. Appropriate changes to BWRVIP-41 to identify and describe this limitation are included in Appendix B, Section B.1.	The NMP1 reactor internals design does not include jet pump assemblies.
<u>Limitation 6 – Jet Pump Holddown Beam Stress Relaxation:</u>	The NMP1 reactor internals design does not include jet pump assemblies.

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Jet pump holddown beams having peak neutron fluence exceeding 7.0×10^{20} n/cm² (E > 1.0 MeV) for Group 2 beams or 5.8×10^{20} n/cm² (E > 1.0 MeV) for Group 3 beams require plant-specific disposition. This limitation ensures that sufficient preload to prevent jet pump disassembly and potential damage is maintained. Plant-specific disposition may include refined analysis to demonstrate adequate preload remains for operation at higher neutron fluences. Alternatively, plants may replace or re-tension beams with neutron fluence exceeding the threshold value. This limitation is applicable to BWRVIP-41. Appropriate changes to BWRVIP-41 to identify and describe this limitation are included in Appendix B, Section B.1. <u>Limitation 7 – Core Shroud Repair Hardware Aging Management:</u> Core shroud tie rod repairs require plant-specific evaluation. Inspections should, as a minimum, meet the requirements listed in BWRVIP-76, Rev. 1-A. However, additional evaluations must be performed to address aging management associated with operation beyond the original repair hardware service life specified by the designer. See Section 4.3.13 for additional discussion. Also see Appendix B, Section B.5.	NMP1 installed a core shroud tie-rod repair during the refueling outage in 1995. Subsequent tie-rod inspections meet the requirements of BWRVIP-76, Revision 1-A and vendor repair design requirements. In response to the tie-rod cracking observed at Hatch Unit 1, NMP1 replaced all existing tie rod upper supports and tie rod nuts during the refueling outage in 2007. A new baseline exam was performed during the refueling outage in 2009. Re-inspection of all four tie-rods and their upper supports was performed during the refueling outage in 2019. No indications of cracking were found. NMP1 will continue inspecting the tie-rod hardware and upper supports per BWRVIP-76, Revision 1-A and vendor repair design requirements. NMP1 plant specific fluence projections were performed for the NMP1 core shroud tie-rod repair assemblies. The projected fluence at the end of the subsequent period of extended operation for the core shroud tie-rod repair hardware is below the vendor

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	design requirement. The Core Shroud Stabilizer Assembly Preload Relaxation Analysis has been identified as a TLAA that is evaluated in SLRA Section 4.2.7. No further actions are required.

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.