Monticello Nuclear Generating Plant
Docket 50-263
Renewed Facility Operating License No. DPR-22
L-MT-23-001

Monticello Nuclear Generating Plant

Unit 1

Subsequent License Renewal Application

January 2023

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Monticello Nuclear Generating Plant

Subsequent License Renewal Application
Sections 1 - 4 and Appendices A - D

January 2023

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1.0 ADMINISTRATIVE INFORMATION

Pursuant to Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR 54), *Requirements for Renewal of Operating Licenses for Nuclear Power Plants* (Reference 1.6.1), this subsequent license renewal application (SLRA) seeks renewal for an additional 20-year term of the facility operating license (DPR-22) for Monticello Nuclear Generating Plant (MNGP) Unit 1 (Reference 1.6.2). The SLRA includes renewal of the source, special nuclear, and byproduct materials licenses that are combined in the license.

The SLRA is based on the guidance provided by the Nuclear Regulatory Commission (NRC) in NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants* (Reference 1.6.3), Regulatory Guide (RG) 1.188, Revision 2, *Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses* (Reference 1.6.4), and the guidance provided by Nuclear Energy Institute (NEI) 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal* (Reference 1.6.5).

The SLRA is intended to provide sufficient information for the NRC to complete its technical and environmental reviews pursuant to 10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*, and 10 CFR Part 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions* (Reference 1.6.6). The SLRA is provided to meet the standards required by 10 CFR 54.29 in support of the issuance of the subsequent renewed operating license for MNGP.

1.1 GENERAL INFORMATION

The following is general information required by 10 CFR 54.17 and 10 CFR 54.19.

1.1.1 Name of Applicant

Northern States Power Company, a Minnesota corporation (NSPM) (Reference ML20352A349), the operating licensee, hereby applies for renewed operating license for MNGP Unit 1. NSPM submits this application individually and as a wholly owned utility operating subsidiary of Xcel Energy Corporation (Xcel Energy).

1.1.2 Address of Applicant

Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Address of the Monticello Nuclear Generating Plant:

Monticello Nuclear Generating Plant
2807 West County Road 75
Monticello, MN 55362

1.1.3 Description of Business or Occupation of Applicant

NSPM is a wholly owned utility operating subsidiary of Xcel Energy Corporation (Xcel Energy) (Reference 1.6.7). Transfer of operating authority for the plant from NSPM to Nuclear Management Company, LLC was approved by the Nuclear Regulatory Commission (NRC) in License Amendment 110 (Reference ML003745555). The operating authority was transferred back to NSPM as approved by the NRC in License Amendment 156 (Reference ML082590110).

NSPM is an operating utility engaged in the generation, transmission and distribution of electricity and the transportation, storage, and distribution of natural gas. NSPM provides generation, transmission, and distribution of electricity in Minnesota, North Dakota, and South Dakota. NSPM also purchases, distributes, and sells natural gas to retail customers and transports customer-owned gas in Minnesota, North Dakota, and South Dakota. NSPM provides retail electric utility service to approximately 1.5 million customers and gas utility service to approximately 500,000 customers.

The Federal Energy Regulatory Commission (FERC) has jurisdiction over rates for electric transmission service in interstate commerce and wholesale electric energy, hydro facility licensing and certain other activities of NSPM. Federal, state, and local agencies also have jurisdiction over many of NSPM's other activities, including regulation of retail rates and environmental matters.

Retail rates, services, and other aspects of NSPM operations are subject to the jurisdiction of the Minnesota Public Utilities Commission, the North Dakota Public Service Commission and the South Dakota Public Utilities Commission (SDPUC) within their respective states.

The current MNGP Unit 1 operating license will expire as follows:

- At midnight on September 8, 2030, for MNGP (Renewed Facility Operating License No. DPR-22)

NSPM will continue as the licensed operator on the subsequent renewed operating license.

1.1.4 Organization and Management of Applicant

MNGP is owned by NSPM with the principal office located in Minneapolis, MN.

NSPM is not owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. NSPM makes this application on their own behalf and is not acting as an agent or representative of any other person.

The names and business addresses of NSPM directors and principal officers are listed below. All persons listed are U.S. citizens.

NSPM Directors and Principal Officers

Name	Title	Address
Robert C. Frenzel	President, Chief Executive Officer, and Chairman	414 Nicollet Mall Minneapolis, MN 55401
Christopher Clark	President, Xcel Energy – MN, SD, ND	414 Nicollet Mall Minneapolis, MN 55401
Brian Van Abel	Executive Vice President and Chief Financial Officer	414 Nicollet Mall Minneapolis, MN 55401
Timothy O’Connor	Executive Vice President and Chief Operations Officer	414 Nicollet Mall Minneapolis, MN 55401
Brett C. Carter	Executive Vice President, Group President, Utilities and Chief Customer Officer	414 Nicollet Mall Minneapolis, MN 55401
Amanda Rome	Executive Vice President, Chief Legal, and Compliance Officer	414 Nicollet Mall Minneapolis, MN 55401
Patricia Correa	Senior Vice President, Chief Human Resources Officer	414 Nicollet Mall Minneapolis, MN 55401
Peter A. Gardner	Senior Vice President, Chief Nuclear Officer	414 Nicollet Mall Minneapolis, MN 55401
Paul Johnson	Vice President, Treasurer, and Investor Relations	414 Nicollet Mall Minneapolis, MN 55401
Amy Schneider	Vice President, Corporate Secretary and Managing Attorney	414 Nicollet Mall Minneapolis, MN 55401
Melissa Ostrom	Vice President, Controller	414 Nicollet Mall Minneapolis, MN 55401
Kristin Westlund	Assistant Secretary	414 Nicollet Mall Minneapolis, MN 55401
Patricia L. Martin	Assistant Treasurer	414 Nicollet Mall Minneapolis, MN 55401

NSPM Board of Directors

Name	Address
Robert C. Frenzel	414 Nicollet Mall Minneapolis, MN 55401
Christopher Clark	414 Nicollet Mall Minneapolis, MN 55401
Brian Van Abel	414 Nicollet Mall Minneapolis, MN 55401
Brett C. Carter	414 Nicollet Mall Minneapolis, MN 55401

1.1.5 Class of License, the Use of the Facility, and the Period of Time for which the License is Sought

NSPM requests subsequent renewal of the operating license issued under Section 104b of the Atomic Energy Act of 1954, as amended, for MNGP Unit 1 (License No. DPR-22), for a period of 20 years beyond the expiration of the current renewed operating license.

This SLRA would extend the renewed operating license for MNGP from midnight on September 8, 2030 to midnight September 8, 2050. Finally, this SLRA includes a request for renewal of those NRC source material, special nuclear material, and by-product material licenses that are subsumed into or combined with the current renewed operating license issued pursuant to 10 CFR Parts 30, 40 and 70.

The facility will continue to be known as the Monticello Nuclear Generating Plant and will continue to generate electric power during the subsequent license renewal (SLR) period.

1.1.6 Earliest and Latest Dates for Alterations

NSPM does not propose to construct or alter any production or utilization facility in connection with this SLRA. In accordance with 10 CFR 54.21(b), during NRC review of this SLRA, an annual update to the SLRA to reflect any change to the current licensing basis (CLB) that materially affects the content of the SLRA will be provided.

1.1.7 Listing of Regulatory Agencies having Jurisdiction and Appropriate News Publications

Regulatory Agencies

Regulatory agencies with jurisdiction over the MNGP revenue are:

Federal Energy Regulatory Commission
888 First St. NE
Washington, D.C. 20426

Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Local News Publications

News publications that circulate in the area surrounding MNGP and are considered appropriate to give reasonable notice of this SLRA to those municipalities, private utilities, public bodies, and cooperatives that might have a potential interest in the facility, are as follows:

The Monticello Times
PO Box 420
540 Walnut Street
Monticello, MN 55362

The St. Paul Pioneer Press
1 West Water St.
Suite 200
St. Paul, MN 55107

The St. Cloud Times
3000 Seventh St. N
St. Cloud, MN 56302

The Star Tribune
425 Portland Avenue
Minneapolis, MN 55488-0002

1.1.8 Conforming Changes to Standard Indemnity Agreement

The requirements of 10 CFR 54.19(b) state that SLRAs 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-42 for MNGP (References ML113201358 and ML080920368) states that the agreement shall terminate at the time of expiration of the license. In addition, Amendment 12 to indemnity agreement No. B-42 could not be located in official record, however the NRC provided confirmation that NSP is in compliance with regulations (Reference ML080920368). The license number in indemnity agreement No. B-42 was originally SNM-1114 but was updated to the current operating license No. DPR-22 (Reference ML113201377).

NSPM has reviewed the original indemnity agreement and Amendments 1 through 14, and there is no expiration date specified for operating license DPR-22. Therefore, no changes to the indemnity agreement are deemed necessary as part of this SLRA. Should the license numbers be changed upon issuance of the subsequent renewed license, NSPM requests that conforming changes be made to the indemnity agreement as appropriate.

1.1.9 Restricted Data Agreement

This SLRA does not contain restricted data or other national defense information, and the applicant does not expect that any activity under the subsequent renewed operating license for MNGP will involve such information. However, pursuant to 10 CFR 54.17(f) and (g), and 10 CFR 50.37 (Reference 1.6.8), the applicant agrees that it 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 25, *Access Authorization* (Reference 1.6.9), and/or 10 CFR 95, *Facility Security Clearance and Safeguarding of National Security Information and Restricted Data* (Reference 1.6.10).

1.2 PLANT DESCRIPTION

MNGP is located within the city limits of Monticello, Minnesota on the south bank of the Mississippi River. The plant and approximately 2000 acres of land at the plant site are owned by NSPM.

The reactor is a single-cycle, forced circulation, General Electric BWR-3, low power density boiling water reactor (BWR) producing steam for direct use in a steam-turbine. A General Electric Mark I Primary Containment System, consisting of a steel light bulb-shaped drywell (DW), a steel doughnut-shaped pressure suppression chamber, and interconnecting vent pipes, provides the first containment barrier surrounding the reactor vessel and the Reactor Primary System. Originally the thermal operating power level was 1670 megawatt thermal (MWt), then increased to 1775 MWt prior to the initial License Renewal (LR) Application (LRA) in September 1998 (Reference 1.6.11). Subsequently, in December 2013, the thermal operating power was increased by extended power uprate (EPU) to 2004 MWt (References ML13316B298 and ML13343A006).

Implementation of each of these power uprates involved a power ascension test program which took into account applicable elements of the original startup test program set forth in Updated Safety Analysis Report (USAR) (Reference 1.6.12) Appendix D, *Pre-operational and Startup Tests*. The power ascension program for the 2004 MWt uprate also included testing of the replacement steam dryer which verified that acoustic loads were within predicted limits. The report of the completed 1775 MWt test program was submitted to the NRC in February 1999 (Reference 1.6.13), and the 2004 MWt test results for the steam dryer were submitted to the NRC in October 2015 (Reference 1.6.14).

In March 2014, the reactor operating domain was expanded to include the Maximum Extended Load Line Limit Analysis Plus (MELLLA+) region (Reference 1.6.15). When the MELLLA+ operating domain expansion was implemented, testing was performed to confirm operational performance of the steam dryer, Average Power Range Monitor (APRM) System, reactor core, pressure regulator, reactor water level control, and neutron flux noise. The analysis of the MELLLA+ region concluded that no additional requirements were necessary for any of the safety, balance-of-plant, electrical or auxiliary systems. (Reference ML100280557).In 2014, 2015, and 2017, NRC approval was given for use of a Spent Fuel Pool criticality analysis performed by Framatome, for use of Framatome fuel licensing methods and use of ATRIUM-10XM fuel in the core, and for core operation in a power-flow range called the Extended Flow Window (EFW), which is identical to the MELLLA+ operating domain. (References 1.6.16, 1.6.17, 1.6.18).

NSPM also operates an independent spent fuel storage installation (ISFSI) at the site. The ISFSI is operated under a general license issued pursuant to the provisions of 10 CFR 72 (Reference 1.6.19). Therefore, the ISFSI is not in-scope of SLR.

1.3 APPLICATION STRUCTURE

This SLRA is structured in accordance with RG 1.188, Revision 2, *Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses*, and NEI 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal* as endorsed by RG 1.188. The SLRA is 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* (Reference 1.6.20). NUREG-2191 was used to determine the adequacy of existing aging management programs (AMPs) and to identify existing programs that will be augmented for SLR. The results of the aging management review (AMR), using NUREG-2191, have been documented and are illustrated in table format in Section 3, *Aging Management Review Results*, of this SLRA.

The SLRA is divided into the following 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 SLRA. Included in this section are the names, addresses, business descriptions, as well as other administrative information. This section also provides an overview of the structure of the SLRA, and a listing of acronyms and general references used throughout the SLRA.

Section 2 – *Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results*

Section 2.1 describes and justifies the methods used in the integrated plant assessment (IPA) to identify those structures and components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(2). These methods consist of: (1) scoping, which identifies the systems, structures, and components (SSCs) that are within the scope of 10 CFR 54.4(a), and (2) screening under 10 CFR 54.21(a)(1), which identifies those in-scope SSCs that perform intended functions without moving parts or a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period.

Additionally, the results for scoping and screening of 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 components or component groups and structures that require AMR. Brief descriptions of mechanical systems, electrical and instrumentation and controls (I&C), and structures within the scope of SLR are provided as background information. Mechanical systems, electrical and I&C, and structures intended functions are provided for in-scope systems and structures. For each in-scope system and structure, components requiring an AMR and their associated component intended functions are identified, and appropriate reference to the Section 3 table providing the AMR results is made.

Selected components, such as equipment supports, structural items (e.g., penetration seals, structural bolting, and insulation), 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 AMR are presented in Sections 2.4 and 2.5. Component intended functions and reference to the applicable Section 3 table are provided.

The descriptions of systems in Section 2 identify SLR boundary drawings (SLRBDs) that depict the components subject to AMR for mechanical systems. The drawings are provided in a separate submittal.

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 CLB throughout the subsequent period of extended operation (SPEO). Section 3 presents the results of the AMRs. Section 3 is the link between the scoping and screening results provided in Section 2 and the AMPs provided in Appendix B.

AMR results are presented in tabular form, in a format in accordance with NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants*. For mechanical systems, AMR results are provided in Sections 3.1 through 3.4 for the Reactor Coolant System (RCS), Engineered Safety Features (ESF), Auxiliary Systems, and Steam and Power Conversion (S&PC) Systems, respectively. AMR results for structures and component supports are provided in Section 3.5. AMR results for electrical and instrumentation and control commodities are provided in Section 3.6.

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

Section 4 – *Time-Limited Aging Analyses*

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

Appendix A – *Updated Safety Analysis Report Supplement*

As required by 10 CFR 54.21(d), the USAR supplement contains a summary of activities credited for managing the effects of aging for the SPEO. A summary description of the evaluation of TLAAs for the SPEO is also included. In addition, summary descriptions and dispositions of SLR commitments are provided. The SLR commitments are identified in Table A-3 of Appendix A of this SLRA; the information in Appendix A is intended to fulfill the requirements of 54.21(d). Following issuance of the renewed license, the material contained in this appendix will be incorporated into the USAR.

Appendix B – *Aging Management Programs*

This appendix describes the programs and activities that are credited for managing aging effects for components or structures during the SPEO based upon the AMR results provided in Section 3 and the TLAAs results provided in Section 4.

Sections B.2.2 and B.2.3 discuss those programs that are contained in Chapter X and Chapter XI, respectively, of NUREG-2191. A description of the AMP is provided, and a conclusion based upon the results of an evaluation against each of the 10 elements provided in NUREG-2191 is drawn. In some cases, exceptions, justifications, and/or enhancements for managing aging are provided for specific NUREG-2191 elements. Additionally, operating experience (OE) related to the AMP is provided. Plant-specific AMPs, if needed, are included in these sections, and evaluated using the guidance in Appendix A of NUREG-2192, Section A.1.2.3, *Aging Management Program Elements*.

Appendix C – *Response to BWRVIP License Renewal Applicant Action Items*

This appendix is optional. For MNGP, this appendix addresses plant-specific activities identified in the Boiling Water Reactor Vessel Internals Project (BWRVIP) for BWRs, for aging management of reactor vessel internals (RVI) or Licensee Action Items (LAIs). In this appendix, the SLRA addresses each of those BWR licensee specific activities as applicable to MNGP. The latest SLRAs on the NRC website, specific to the applicant's plant type, were used as guidance during the generation of this appendix to the SLRA.

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 SPEO. There are no technical specification changes identified as necessary to manage the effects of aging during the SPEO.

Appendix E – Environmental Information – Monticello Nuclear Generating Plant

This appendix satisfies the requirements of 10 CFR 54.23 to provide a supplement to the environmental report (ER) that complies with the requirements of subpart A of 10 CFR 51 for MNGP.

1.4 CURRENT LICENSING BASIS CHANGES DURING NRC REVIEW

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

In accordance with 10 CFR 54.21(d), MNGP will maintain (1) a summary description of programs and activities in the USAR for managing the effects of aging, (2) summaries of the TLAA evaluations, and (3) descriptions of the in-scope commitments for the SPEO.

1.5 CONTACT INFORMATION

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

Paul Young
Manager of Routine Projects
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

E-mail: paul.b.young@xcelenergy.com

1.6 GENERAL REFERENCES

1.6.1 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*.

1.6.2 DPR-22, *Renewed Facility Operating License for Monticello Nuclear Generating Plant Unit 1*, ADAMS Accession No. ML052910355, November 8, 2006.

1.6.3 NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants*, United States Nuclear Regulatory Commission, July 2017, ADAMS Accession No. ML16274A402.

1.6.4 RG 1.188, Revision 2, *Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses*, ADAMS Accession No. ML20017A265.

1.6.5 NEI 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal Rule*, December 2017, ADAMS Accession No. ML17339A599.

1.6.6 10 CFR 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions*.

1.6.7 NRC (C F Lyon) letter to NSP (W H Brunetti), *Issuance of Conforming Amendment re: Transfer of Facility Operating License from Northern States Power Company to a New Utility Operating Company Subsidiary (TAC No. MA7003)*, dated August 18, 2000, ADAMS Accession No. ML003742968.

1.6.8 10 CFR 50, *Domestic Licensing of Production and Utilization Facilities*.

1.6.9 10 CFR 25, *Access Authorization*.

1.6.10 10 CFR 95, *Facility Security Clearance and Safeguarding of National Security Information and Restricted Data*.

1.6.11 NRC (T. Kim) letter to NSP (R O Anderson), *Issuance of Amendment RE: Power Uprate Program (TAC No. M96238)*, dated September 16, 1998, ADAMS Accession No. ML020920138.

1.6.12 Monticello Updated Safety Analysis Report. Refer to the USAR-List of Effective Pages (LOEP) Revision 40P for the revision numbers for individual USAR Sections.

1.6.13 NSP (M F Hammer) letter to the NRC, *Power Rerate Test Program Startup Report*, dated February 18, 1999, ADAMS Accession No. 9903030028.

1.6.14 NSPM letter L-MT-15-074 (Peter A. Gardner) to NRC, *Monticello Extended Power Uprate: Submittal of Power Ascension Testing Results for Replacement Steam Dryer (TAC No. MF6730)*, dated October 12, 2015, ADAMS Accession No. ML15289A073.

1.6.15 NRC (T A Beltz) letter to NSPM (K D Fili), *Monticello Nuclear Generating Plant Issuance of Amendment No. 180 to Renewed Facility Operating License Regarding Maximum Extended Load Line Limit Analysis Plus (TAC No. ME3145)*, dated March 28, 2014, ADAMS Accession No. ML14035A248.

1.6.16 NRC (T. Beltz) letter to NSPM (K Fili), *Monticello Nuclear Generating Plant Issuance of Amendment to Revise the Technical Specification to Support Fuel Storage System Changes (TAC No. ME9893) (Am 182)*, October 24, 2014, ADAMS Accession No. ML15160A207.

1.6.17 NRC (T. Beltz) letter to NSPM (P. Gardner), *Monticello Nuclear Generating Plant Issuance of Amendment to Transition to AREVA ATRIUM 10XM Fuel and AREVA Safety Analysis Methods (TAC No. MF2479) (Am. 188)*, June 5, 2015, ADAMS Accession No. ML15072A141.

1.6.18 NRC (R. Kuntz) letter to NSPM (P. Gardner), *Monticello Nuclear Generating Plant- Issuance of Amendment RE: Extended Flow Window (CAC NO. MF5002)*, February 23, 2017, ADAMS Accession No. ML17054C394.

1.6.19 10 CFR 72, *Licensing Requirements for the Independent Storage of Spent Nuclear Fuel, High-Level Radioactive Waste, and Reactor-Related Greater Than Class C Waste*.

1.6.20 NUREG-2191, *Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report*, Volumes 1 and 2, United States Nuclear Regulatory Commission, July 2017, ADAMS Accession Nos. ML16274A389 and ML16274A399.

1.6.21 NEI 95-10, Revision 6, *Industry Guidelines for Implementing the Requirements of 10 CFR 54 – The License Renewal Rule, Appendix F, Industry Guidance on Revised 54.4(a)(2) Scoping Criterion (Non-Safety Affecting Safety)*, June 2005.

1.6.22 NRC Letter to NSPM, *Subject: Monticello Nuclear Generating Plant, Exemption from the Requirements of 10 CFR Part 50, Appendix R, Section III.G.2 (CAC No. MF9586)*, dated May 1, 2018, ADAMS Accession No. ML18093A108.

1.6.23 NRC Letter to NSPM, Subject: *Monticello Nuclear Generating Plant, Exemption from the Requirements of 10 CFR Part 50, Appendix R, Section III.G.2.a (EPID L-2018-LLE-0001)*, dated Feb. 14, 2019, ADAMS Accession No. ML18289A735.

1.6.24 *Monticello Nuclear Generating Plant Application for Renewed Operating License*, March 16, 2005, ADAMS Accession No. ML050880241.

1.6.25 NUREG-1865, *Safety Evaluation Report Related to the License Renewal of the Monticello Nuclear Generating Plant*, ADAMS Accession No. ML063050414.

1.6.26 NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants: Resolution of Generic Technical Activity A-36*, ADAMS Accession No. ML070250180.

1.6.27 RG 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*, ADAMS Accession No. ML010890301.

1.6.28 RG 1.54, Revision 3, *Service Level I, II, III, and In-Scope License Renewal Protective Coatings Applied To Nuclear Power Plants*, ADAMS Accession No. ML17031A288.

1.6.29 NUREG-0933, *Resolution of Generic Safety Issues*.

1.6.30 BWRVIP-315, *Reactor Internals Aging Management Evaluation for Extended Operations*.

1.6.31 NUREG-0737, *Clarification of TMI Action Plan Requirements*, ADAMS Accession No. ML051400209.

1.6.32 NEI 14-13, Revision 1, *Use of Industry Operating Experience for Age-related Degradation and Aging Management Programs*.

1.6.33 NEI 14-12, Revision 1, *Aging Management Program Effectiveness.*

1.6.34 EPRI 3002002623, , BWRVIP-190, Revision 1, *BWR Vessel and Internals Project, Volume 1: BWR Water Chemistry Guidelines - Mandatory, Needed, and Good Practice Guidance and Volume 2: BWR Water Chemistry Guidelines - Technical Basis*.

1.6.35 NUREG/CR-4513, Revision 2, *Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR System,* May 2016, ADAMS Accession No. ML16145A082.

1.6.36 RG 1.147, *Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1*, ADAMS Accession No. ML031560264.

1.6.37 NRC GL 89-08, dated July 20, 1989, Letter to USNRC (Response to) *Erosion/Corrosion Induced Pipe Wall Thinning.*

1.6.38 NSAC-202L-R4, R*ecommendations for an Effective Flow-Accelerated Corrosion Program, Palo Alto, California: Electric Power Research Institute*, November 2013.

1.6.39 EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants.*, April 1988.

1.6.40 EPRI 1015336, *Nuclear Maintenance Application Center: Bolted Joint Fundamentals*, December 2007.

1.6.41 EPRI 1015337, *Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints*, December 2007.

1.6.42 NRC GL 89-13, *Service Water System Problems Affecting Safety-Related Equipment*.

1.6.43 EPRI 1010059, *Service Water Piping Guideline,* September 2005.

1.6.44 ASME Safety Standard B30.2, *Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist).*

1.6.45 ASME OM 2012, Division 2, Part 28, *Operation and Maintenance of Nuclear Power Plants*.

1.6.46 EPRI TR-108147, *Compressor and Instrument Air System Maintenance Guide*, 1998.

1.6.47 NFPA 25, *Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*, Quincy, Massachusetts, National Fire Protection Association, 2011

1.6.48 EPRI, Technical Report 1006756, *Fire Protection Equipment Surveillance Optimization and Maintenance Guide*, Electric Power Research Institute, Palo Alto, California, July 2003

1.6.49 IN 2013-06, *Corrosion in Fire Protection Piping Due to Air and Water Interaction,* March 25, 2013, ADAMS Accession No. ML13031A618.

1.6.50 ASTM D714-02, *Standard Test Method for Evaluating Degree of Blistering of Paints*.

1.6.51 EPRI TR-107514, *Age-Related Degradation Inspection Method and Demonstration: In Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application*, May 1998.

1.6.52 RG 1.160, Revision 4, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* ADAMS Accession No. ML18220B281.

1.6.53 Nuclear Management and Resources Council 93-01

1.6.54 ACI 349.3R-02, *Evaluation of Existing Nuclear Safety-Related Concrete Structures*.

1.6.55 ACI 201.1R-08, *Guide for Conducting a Visual Inspection of Concrete in Service*.

1.6.56 Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11

1.6.57 ASTM D 5163-08, *Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants*, West Conshohocken, Pennsylvania: American Society for Testing and Materials, 2008.

1.6.58 ASTM D5498, *Standard Guide for Developing a Training Program for Personnel Performing Coating and Lining Work Inspection for Nuclear Facilities*, November 2012.

1.7 ACRONYMS

Table 1.7-1
Acronyms

Acronym	Description
AC	Alternating Current
ADAMS	Agencywide Documents Access and Management System
ALE	Adverse Localized Environment
ACI	American Concrete Institute
ACSR	Aluminum Conductor Steel Reinforced
AIR	Instrument and Service Air
AMP	Aging Management Program
AMR	Aging Management Review
AN2	Alternate Nitrogen
ANSI	American National Standards Institute
APR	Automatic Pressure Relief
APRM	Average Power Range Monitor
AR	Action Request
ARI	Alternate Rod Injection
ARM	Area Radiation Monitor
ART	Adjusted Reference Temperature
ASCM	Alternate Shutdown Cooling Method
ASD	Alternate Shutdown
ASME	American Society of Mechanical Engineers
AST	Alternate Source Term
ASTM	American Society for Testing of Materials
ATWS	Anticipated Transients Without Scram
BIS	Biocide Injection System
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group

Table 1.7-1
Acronyms

Acronym	Description
BWRVIP	Boiling Water Reactor Vessel Internals Project
CA	Calculation
CAP	Corrective Action Program
CASS	Cast Austenitic Stainless Steel
CCCW	Closed-Cycle Cooling Water
CDR	Main Condenser
CE	Combustion Engineering
CFR	Code of Federal Regulations
CFW	Condensate and Feedwater
CGC	Combustible Gas Control
CHM	Chemistry Sampling
CLB	Current Licensing Basis
CMAA	Crane Manufactures Association of America
Cr	Chromium
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
CRE	Control Room Envelope
CSP	Core Spray
CST	Condensate Storage
CUF	Cumulative Usage Factor
CUF_{en}	Cumulative Usage Factor (Environmental-Assisted Fatigue)
CV	Control Valve
CWT	Circulating Water
DBA	Design Basis Accident
DBD	Design Basis Document
DBE	Design Basis Event

Table 1.7-1
Acronyms

Acronym	Description
DC	Direct Current
DG	Diesel Generator
DGB	Emergency Diesel Generator Building
DGN	Emergency Diesel Generator (System Reference Only)
DOL	Diesel Oil System
DORT	Discrete Ordinates Transport Code
dP	Differential Pressure
DPR	Division of Power Reactors
DW	Drywell
DWS	Demineralized Water System
EAF	Environmentally-Assisted Fatigue
ECCS	Emergency Core Cooling System
ECP	Electrochemical Potential
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EFB	Emergency Filtration Train Building
EFPY	Effective Full Power Years
EFT	Emergency Filtration Train
EFW	Extended Flow Window
EMA	Equivalent Margin Analysis
EOCI	Electric Overhead Crane Institute
EOL	End of Life
EPA	Electrical Penetration Assemblies
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate
EQ	Environmental Qualification

Table 1.7-1
Acronyms

Acronym	Description
ESF	Engineered Safety Features
ESW	Emergency Service Water
FAC	Flow-Accelerated Corrosion
Fe	Iron
F_{en}	Environmental Fatigue Correction Factor
FERC	Federal Energy Regulatory Commission
FHA	Fire Hazards Analysis
FIR	Fire (System)
FOH	Diesel Fuel Oil Transfer House
FP	Fire Protection
FPC	Fuel Pool Cooling and Cleanup
FW	Feedwater
GALL	Generic Aging Lessons Learned
GE	General Electric
GL	Generic Letter
GSI	Generic Safety Issue
HELB	High Energy Line Break
HEPA	High Efficiency Particulate Filter
HGR	Hangers and Supports
HOA	Hydrogen-Oxygen Analyzing
HPB	HPCI Building
HPCI	High Pressure Coolant Injection
HPV	Hard Pipe Vent
HTV	Heating and Ventilation
HVAC	Heating, Ventilation, and Air Conditioning
HWC	Hydrogen Water Chemistry

Table 1.7-1
Acronyms

Acronym	Description
I&C	Instrumentation & Controls
IASCC	Irradiation Assisted Stress Corrosion Cracking
ICMH	Incore-Monitoring Housing
ID	Inside Diameter
IEB	Inspection and Enforcement Bulletin
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IGSCC	Intergranular Stress Corrosion Cracking
IN	Information Notice
INPO	Institute of Nuclear Power Operations
INS	Intake Structure
IPA	Integrated Plant Assessment
IR	Insulation Resistance
IRM	Intermediate Range Monitor
ISFSI	Independent Spent Fuel Storage Installation
ISG	Interim Staff Guidance
ISI	In-Service Inspection
ISP	Integrated Surveillance Program
IWB	Requirements for Class 1 Components of Light-Water Cooled Power Plants
IWC	Requirements for Class 2 Components of Light-Water Cooled Power Plants
IWD	Requirements for Class 3 Components of Light-Water Cooled Power Plants
IWE	Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants
IWF	Requirements for Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants
IWL	Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants
K_{IC}	Reference Stress Intensity Factor As A Function Of The Metal Temperature T and The Metal References Nil-Ductility Temperature RT_{NDT}
ksi	One KIP (1000 Lbs or 1 kilo-Pound) per Square Inch, 1000 psi

Table 1.7-1
Acronyms

Acronym	Description
kV	1000 Volts or 1 Kilo-Volt
LAI	Licensee Action Item
LLC	Limited Liability Company
LO	Lubricating Oil
LOCA	Loss-of-Coolant-Accident
LOEP	List of Effective Pages
LOOP	Loss of Offsite Power
LP	Low Pressure
LPCI	Low Pressure Coolant Injection
LPRM	Local Power Range Monitor
LR	License Renewal
LRA	License Renewal Application
LWR	Light Water Reactor
MCC	Motor Control Center
MCM	Thousands of Circular Mils
MCR	Main Control Room
MEB	Metal Enclosed Bus
MELLLA+	Maximum Extended Load Line Limit Analysis Plus
MeV	Million Electron Volts
MG	Motor Generator
MIC	Microbiologically Induced Corrosion
MNGP	Monticello Nuclear Generating Plant
MoS_2	Molybdenum Disulfide
MSIV	Main Steam Isolation Valve
MSO	Multiple Spurious Operation
MST	Main Steam

Table 1.7-1
Acronyms

Acronym	Description
MUD	Makeup Demineralizer
MVP	Mechanical Vacuum Pump
MW	Megawatts
MWt	Megawatt Thermal
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
n/cm^2	Neutrons per square centimeter
N_2	Nitrogen
Ni	Nickel
NMS	Neutron Monitoring System
NPS	Nominal Pipe Size
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSAS	Non-Safety Affecting Safety
NSPM	Northern States Power Company – Minnesota
NSR	Non-Safety Related
NSSS	Nuclear Steam Supply System
NTTF	Japan Near Term Task Force
NUMARC	Nuclear Utility Management and Resource Council
NUREG	Designation of Publication Prepared by NRC Staff
OAR	Owners Activity Reports
OBE	Operating Basis Earthquake

Table 1.7-1
Acronyms

Acronym	Description
OCA	Owner Control Area
OE	Operating Experience
OGB	Off Gas Storage and Compressor Building
OGS	Off Gas Stack
OSP	Off Site Power
P&ID	Piping and Instrumentation Diagram
PAB	Plant Administration Building or Plant Control and Cable Spreading Structure
PAS	Post-Accident Sampling
PCAC	Primary Containment Atmospheric Control
PCT	Primary Containment
PCM	Primary Containment Mechanical
PEO	Period of Extended Operation
PH	Precipitate hardened
pH	Concentration of Hydrogen Ions
PM	Preventative Maintenance
PPS	Plant Protection System
psi	Pounds Per Square Inch
P-T	Pressure-Temperature
PTS	Pressurized Thermal Shock
PUAR	Plant Unique Analysis Report
PVC	Polyvinyl Chloride (Plastic)
PWR	Pressurized Water Reactor
QA	Quality Assurance
RAD	Radwaste Solid & Liquid
RAI	Request for Additional Information
RAMA	Radiation Analysis Modeling Application

Table 1.7-1
Acronyms

Acronym	Description
RB	Reactor Building
RBC	Reactor Building Closed Cooling Water
RBM	Rod Block Monitor
RCI	Reactor Core Isolation Coolant System
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
REC	Reactor Recirculation
RFP	Reactor Feedwater Pump
RG	Regulatory Guide (NRC)
RHR	Residual Heat Removal
RHV	Reactor Head Vent
RI-ISI	Risk Informed In-Service Inspection
RIT	Reactor Pressure Vessel Internals (System)
RIVE	Radiation Induced Volumetric Expansion
RLC	Reactor Level Control
RMC	Reactor Manual Control
RMS	Radiation Monitoring System
RO	Reverse Osmosis
RPT	Recirculation Pump Trip
RPV	Reactor Pressure Vessel
RHRSW	Residual Heat Removal Service Water
RT	Radiography Testing
RT_{NDT}	Reference Temperature for Nil Ductility Transition
RV	Relief Valve
RVI	Reactor Vessel Internals

Table 1.7-1
Acronyms

Acronym	Description
RWB	Radioactive Waste Building
RWC	Reactor Water Cleanup
RWE	Rod Withdrawal Error
RB	Reactor Building
S&PC	Steam and Power Conversion
SAS	Structures Affecting Safety
SBGT	Standby Gas Treatment
SBO	Station Blackout
SC	Structure and Component
SCC	Stress Corrosion Cracking
SCT	Secondary Containment
SDPUC	South Dakota Public Utilities Commission
SE	Safety Evaluation
SER	Safety Evaluation Report
SF	Safety Factor
SFP	Spent Fuel Pool
SGTS	Standby Gas Treatment System
SHE	Standard Hydrogen Electrode
SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SLRBD	Subsequent License Renewal Boundary Drawing
SO_2	Sulfur dioxide
SPEO	Subsequent Period of Extended Operation
SR	Safety-Related

Table 1.7-1
Acronyms

Acronym	Description
SRM	Source Range Monitor
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for License Renewal
SRP-SLR	Standard Review Plan for Subsequent License Renewal
SRV	Safety Relief Valve
SS	Stainless Steel
SSA	Safe Shutdown Analysis
SSC	System, Structure, or Component
SSP	Supplemental Surveillance Program
SSW	Service & Seal Water
SW	Service Water
TAC	Technical Assignment Control (internal NRC work management tool)
TAP	Torus Attached Piping
TGB	Turbine Building
TGS	Turbine Generator System
TGSCC	Transgranular Stress Corrosion Cracking
TIP	Traversing In-Core Probe
TLAA	Time-Limited Aging Analysis
TR	Technical Report
TSV	Turbine Stop Valve
UAC	Uninterruptible Alternating Current
UDB	Underground Duct Bank
U_{en}	Environmentally Assisted Fatigue Usage Factor
USAR	Updated Safety Analysis Report
USAS	United States of America Standards
USE	Upper Shelf Energy

Table 1.7-1
Acronyms

Acronym	Description
USI	Unresolved Safety Issue
UT	Ultrasonic Testing
UV	Ultraviolet
VDC	Volts-Direct Current
VT	Visual Examination
WDW	Well and Domestic Water
WO	Work Order
XLPE	Cross-Linked Polyethylene
Zn	Zinc

2.0 SCOPING AND SCREENING METHODOLOGY FOR IDENTIFYING STRUCTURES AND COMPONENTS SUBJECT TO AMR AND IMPLEMENTATION RESULTS

This section describes the process for identifying structures and components (SCs) subject to AMR in the MNGP Integrated Plant Assessment (IPA). For the systems, structures, and components (SSCs) within the scope of SLR, 10 CFR 54.21(a)(1) requires the SLR applicant to identify and list those SCs subject to AMR. Furthermore, 10 CFR 54.21(a)(2) requires that the methods used to implement the requirements of 10 CFR 54.21(a)(1) be described and justified. Section 2.0 of this application satisfies these requirements.

The scoping and screening portion of the IPA 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 SLR in accordance with 10 CFR 54.4. The intended functions that are the bases for including the systems and structures within the scope of SLR are also identified during the scoping process. Screening refers to the process of determining which components associated with the in-scope systems and structures are subject to AMR in accordance with 10 CFR 54.21(a)(1) requirements. A detailed description of the MNGP scoping and screening process is provided in Section 2.1.

The scoping and screening methodology is implemented in accordance with NEI 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal*. The plant level scoping results identify the systems and structures within the scope of SLR in Section 2.2. The screening results identify components subject to AMR in the following SLRA sections:

- Section 2.3 for mechanical systems
- Section 2.4 for structures
- Section 2.5 for electrical and instrumentation and control (I&C) systems

2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 Introduction

This introduction provides an overview of the scoping and screening process used for MNGP SLR project. 10 CFR 54.21 requires that each SLRA contain an IPA. The content of the IPA, based on the specific criteria in 10 CFR 54.21(a), generally consists of the following:

(1) Identifying the SSCs in the scope of the rule;

(2) Identifying the SCs subject to AMR;

(3) Assuring that the effects of aging are adequately managed.

The IPA methodology consists of three distinct processes: scoping, screening, and AMRs. The IPA process developed for the original MNGP LR project was used as a starting point for development of the IPA scoping and screening process for SLR.

The initial step in the scoping process was to define the entire plant in terms of systems and structures. The systems and structures were then individually evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3) to determine if the systems or structures perform or support a safety-related (SR) function, if failure of the systems or structures prevent performance of a SR function, or if the systems or structures perform functions that are integral to one of the five LR regulated events. The intended function(s) that are the bases for including systems and structures within the scope of SLR were also identified.

If any portion of a mechanical system met the scoping criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3), it was included within the scope of SLR. The mechanical systems in the scope of SLR were then further evaluated to determine the system components that support the identified system intended function(s). The individual mechanical screening and AMR reports provide the details on the boundaries of in-scope mechanical systems.

If any portion of a structure met the scoping criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3), the structure was included within the scope of SLR. Structures in the scope of SLR were then further evaluated to determine those structural components that are required to perform or support the identified structure intended function(s). The portions of each structure that are required to support the SLR intended function(s) are identified in the individual civil structural screening and AMR reports.

Electrical and I&C systems were scoped using the same methodology as mechanical systems and structures per the scoping criteria in 10 CFR 54.4 (a)(1), (a)(2), and (a)(3). Electrical and I&C components that are part of in-scope electrical and I&C systems and in-scope mechanical systems were included within the scope of SLR.

After completion of the scoping and boundary evaluations, the screening process was performed to evaluate the SCs within the scope of SLR to identify the long-lived and passive SCs subject to an AMR. The passive intended functions of SCs subject to AMR were also identified. Additional details on the screening process are provided in Section 2.1.5.

Selected components, such as equipment supports, structural items, and passive electrical components, were scoped and screened as commodities. The structural commodities and electrical commodities were evaluated collectively.

2.1.2 Technical Reports

Technical reports (TRs) were prepared in support of the SLRA. Engineers experienced in nuclear plant systems, programs, and operations prepared, reviewed, and approved the technical reports. The technical reports contain evaluations and bases for decisions or positions associated with SLR requirements as described below. Technical reports are prepared, reviewed, and approved in accordance with controlled project instructions, and are based on CLB source documents described in the subsections within Section 2.1.3. All of this work was performed under an NRC-approved Appendix B quality assurance (QA) program.

2.1.2.1 Subsequent License Renewal Systems and Structures List

Criteria for determining which SSCs should be reviewed and evaluated for inclusion in the scope of SLR is provided in 10 CFR 54.4. The scoping process to identify systems and structures that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) is performed on systems and structures using documents that form the CLB and other information sources (e.g., design drawings, design basis documents (DBDs), and TRs). The CLB for MNGP has been defined in accordance with the definition provided in 10 CFR 54.3. The key information sources that form the CLB include the USAR, Technical Specifications, and the docketed licensing correspondence (see the subsections within Section 2.1.3).

The aspects of the scoping process used to identify systems and structures that satisfy the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3) are described in Sections 2.1.2.2, 2.1.2.3, and 2.1.2.4, respectively. The initial step in scoping is defining the entire plant in terms of major systems and structures. As no single document source exists for MNGP, a scoping technical report was prepared to establish a comprehensive list of SLR systems and structures and to document the basis for the list.

The grouping of the MNGP SLR systems and structures is based on the guidance provided in NEI 17-01 and NUREG-2191. The complete list of systems and structures evaluated in the scoping technical report are provided in Table 2.2-1. Initial LR systems are listed for reference, and some are represented together to match the guidance/systems more closely in NUREG-2191.

Certain structures and equipment were excluded at the outset because they are not considered to be SSCs 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.

SLR systems and structures were grouped into the following categories:

- Reactor Vessel, Internals, and Reactor Coolant System
- ESF
- Auxiliary Systems
- S&PC System
- Containments, Structures, and Component Supports
- Electrical and I&C

2.1.2.2 Safety-Related Criteria Pursuant to 10 CFR 54.4(a)(1)

SR systems and structures are included within the scope of SLR in accordance with 10 CFR 54.4(a)(1) scoping criterion. The current definition of SR per 10 CFR 54.4(a)(1) is:

> *Safety-related systems, structures, and components that are relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions*
>
> *(i) The integrity of the reactor coolant pressure boundary;*
>
> *(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or*
>
> *(iii) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in §50.34(a)(1), §50.67(b)(2), or §100.11 of this chapter, as applicable.*

The design, construction, and licensing of MNGP predates this definition of SR. However, the SSCs which perform SR functions for MNGP Design Basis Events (DBEs) have been included in the scope of LR and the identification of these components and commodities was based on a variety of information sources. The MNGP definition of SR functions are not identical to the definition in 10 CFR 54.4(a)(1). The definition of the SR function and associated SR items at MNGP differs from that provided in 10 CFR 54.4(a)(1) only for the specific guidelines identified for the third function (iii). The MNGP definition only identifies 10 CFR 100.11, 10 CFR 100 Appendix A, or 10 CFR 50.67 as the guidelines that need to be met for off-site exposure. Inclusion of 10 CFR 100 Appendix A adds additional requirements to the definition of SR and is conservative.

The MNGP definition of SR is technically equivalent for the purposes of scoping, and there is reasonable assurance that all components falling within the scope of 10 CFR 54.4(a)(1) were identified.

Safety classifications of SSCs are included in the Functional Location Classification database and were established based on CLB information, which includes design basis accidents (DBAs), anticipated operational occurrences, natural phenomena, and external events. The DBEs considered for the MNGP CLB are consistent with

10 CFR 50.49(b)(1). USAR Chapter 14 provides the DBE accident analyses for MNGP.

Natural phenomena and external events are described in Chapter 12 of the MNGP USAR and in appropriate sections of the DBDs. Structures designed to withstand DBEs, natural phenomena, and external events are also described in USAR Chapter 12.

The steps to identify systems and structures at MNGP that meet the criteria of 10 CFR 54.4(a)(1) are outlined below:

- The USAR, Technical Specifications, Technical Requirements Manual, DBDs, initial LR Technical Reports/LRA/safety evaluation report (SER), docketed licensing correspondence, and design drawings were reviewed, as applicable.

- Based on the above, LR intended functions relative to the criteria of 10 CFR 54.4(a)(1) were identified for each system and structure determined to be SR.

In December 2006, the NRC issued a license amendment supported by a SER accepting the MNGP implementation of alternate source term (AST) methodology; therefore, the requirements of 10 CFR 50.67 are applicable to MNGP. This SER states that the new role being assigned to the Standby Liquid Control System (SLC) is a SR role. However, this did not change scoping results from initial LR at the component level, as all the SLC components and component intended functions required for this role were already in-scope for other reasons. The only change is at the system scoping level to specify that this system now meets the criteria of 10 CFR 54.4(a)(1) and includes the associated SR system intended function.

A review of modifications completed after initial LR was performed to determine any additional SR components that have been installed in the interim, that need to be included in the scope of this part.

The scoping process to identify SR systems and structures for MNGP is consistent with and satisfies the criteria in 10 CFR 54.4(a)(1).

2.1.2.3 Non-Safety Related Criteria Pursuant to 10 CFR 54.4(a)(2)

10 CFR 54.4(a)(2) states that SSCs within the scope of SLR include non-safety related (NSR) SSCs whose failure could prevent satisfactory accomplishment of the functions identified for SR SSCs. The method utilized for this scoping criterion is consistent with NUREG-2192 and NEI 17-01. Note that Section 3.1.2 of NEI 17-01 references NEI 95-10 (Reference 1.6.21), Appendix F, for industry guidance related to 10 CFR 54.4(a)(2) scoping criteria.

Initial LR 10 CFR 54.4(a)(2) scoping was reviewed with respect to the latest industry and regulatory guidance. Consistent with this guidance, the NSR SSCs that are within the scope of SLR for MNGP fall into three categories:

- NSR SSCs that may have the potential to prevent satisfactory accomplishment of safety functions typically identified in the CLB,
- NSR SSCs directly connected to SR SSCs (typically piping systems), and
- NSR SSCs that are not directly connected to SR SSCs but have the potential to affect SR SSCs through spatial interactions.

The first item includes NSR SSCs credited as mitigative design features or for providing system functions relied on by SR SSCs in the CLB. These NSR SSCs are identified by reviewing the MNGP USAR and other CLB documents. Any NSR SSCs identified during this review are included within the scope of SLR in accordance with 10 CFR 54.4(a)(2).

The remaining two items are NSR SSCs with the potential for physical or spatial interaction with SR SSCs. Scoping of these SSCs is the subject of NEI 95-10, Appendix F. Additional detail on the application of the 10 CFR 54.4(a)(2) scoping criteria is provided in Section 2.1.4.2.

The scoping process to identify NSR systems and structures that can affect SR systems and structures for MNGP is consistent with and satisfies the criteria in 10 CFR 54.4(a)(2).

2.1.2.4 Other Scoping Pursuant to 10 CFR 54.4(a)(3)

10 CFR 54.4(a)(3) states that SSCs within the scope of SLR include systems and structures relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for one or more of the following regulated events:

- Fire Protection (FP) (10 CFR 50.48)
- Environmental Qualification (EQ) (10 CFR 50.49)
- Pressurized Thermal Shock (PTS) (10 CFR 50.61)
- Anticipated Transients Without Scram (ATWS) (10 CFR 50.62)
- Station Blackout (SBO) (10 CFR 50.63)

The scoping process and methodology described below for each of these regulated events is consistent with and satisfies the criteria of 10 CFR 54.4(a)(3).

2.1.2.4.1 Fire Protection (10 CFR 50.48)

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

The scope of systems and structures required for FP to comply with the requirements of 10 CFR 50.48 includes:

- 10 CFR Part 50 Appendix R
- Systems and structures required to demonstrate post-fire safe shutdown capabilities.
- Systems and structures required for fire detection and mitigation.
- Systems and structures required to meet commitments made to Appendix A of Branch Technical Position (BTP) APCSB 9.5-1.

The design of the MNGP FP program is based upon the defense-in-depth concept. Multiple levels of protection are provided so that should a fire occur, it will not prevent safe plant shutdown, and the risk of a radioactive release to the environment is minimized. These levels of protection include fire prevention, fire detection and mitigation, and the capability to achieve and maintain safe shutdown should a fire occur. This protection is provided through compliance with 10 CFR 50.48, 10 CFR Part 50, Appendix R, and commitments made to NRC BTP APCSB 9.5-1, Appendix A. FP features and commitments are described in detail in the USAR 10.3.1, and USAR Appendix J, which includes the safe shutdown analysis (SSA), and the Fire Hazards Analysis (FHA). The SSCs at MNGP that support these multiple levels of protection are in-scope for SLR.

10 CFR 50.48 allows the adoption of National Fire Protection Association (NFPA) 805, *Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants*, as a method of compliance. MNGP has not adopted NFPA 805, and the FP program has not changed significantly since the initial LRA.

The steps to identify systems and structures relied upon for FP at MNGP that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The USAR, Technical Specifications, TRM, initial LR Technical Reports/LRA/SER, licensing correspondence, DBDs, and design drawings were reviewed, as applicable.
- Based on the above, LR intended functions relative to the criterion of 10 CFR 54.4(a)(3) for FP were identified for each system and structure determined to meet this criterion.

Recent licensing actions since initial LR, included the analysis and evaluation of FP considerations for EPU and for the transition to AREVA fuel.

- The EPU Appendix R analyses showed that the FP systems and previous FP analyses were unaffected by EPU. See NRC SER on EPU Sections 2.5.1.4 and 2.6.5. The EPU does not change the credited equipment necessary for post-fire safe-shutdown, nor does it require reroute of essential cables or relocation of essential components/equipment credited for post-fire safe-shutdown. New modifications were required to preclude Multiple Spurious Operation (MSO) of the drywell spray valves, and to preclude MSO of the Main Steam Line Drain Valves. MNGP also performed valve modifications and configuration changes in fuses to preclude fire-induced MSOs from adversely affecting safe shutdown.

- The Appendix R analyses for the use of AREVA fuel and methods confirmed that the analysis performed for EPU were unaffected by the fuel transition. See NRC SER for AREVA fuel and methods Section 2.2.

- In 2018, MNGP received a permanent Appendix R exemption for the Drywell Spray Shorting Switches (see Reference 1.6.22). The new shorting switches are included in-scope of SLR.

- In 2019, MNGP received a permanent Appendix R exemption for the Cable Spreading Room Floor Steel Fireproofing (Reference 1.6.23). No new equipment was installed, but the structural steel and floor of the cable spreading room are in-scope of SLR, as part of the structure.

The scoping process to identify systems and structures relied upon and/or specifically committed to for FP for MNGP is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.2.4.2 Environmental Qualification (10 CFR 50.49)

Certain SR electrical components are required to withstand environmental conditions that may occur during or following a DBA per 10 CFR 50.49. The criteria for determining which equipment requires EQ is defined by 10 CFR 50.49.

The steps to identify components subject to EQ at MNGP that meet the associated criterion of 10 CFR 54.4(a)(3) are outlined below:

- The USAR, Technical Specifications, TRM, EQ Equipment Master List, initial LR Technical Reports/LRA/SER, and licensing correspondence were reviewed, as applicable.

- Based on the above, LR intended functions relative to the criterion of 10 CFR 54.4(a)(3) for EQ were identified for each SSC determined to meet this criterion.

The electrical equipment identified for this part, must be qualified for the worst-case accident environment in which they are required to perform their function. Some of these components will have a specified life duration, which may be less than the duration of the renewed license. These types of components will be addressed as TLAAs and will be discussed in Section 4.0.

An analysis of EQ of plant equipment was performed to address the increased radiation, temperatures, pressures, etc., associated with DBAs when operating at EPU conditions. MNGP reconstituted their Environmental Qualification of Electric Equipment program to incorporate the environmental conditions associated with EPU and revised environmental conditions were incorporated into the EQ Environmental Specifications. The NRC staff concluded that operation at EPU conditions had been adequately addressed; the effects of operation at 2004 MWt on the environmental conditions inside and outside containment have been appropriately considered and the qualification of electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 (Reference ML13316B298).

The scoping process to identify systems and structures relied upon and/or specifically committed to for EQ for MNGP is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.2.4.3 Pressurized Thermal Shock (10 CFR 50.61)

Fracture toughness requirements specified in 10 CFR 50.61 state that licensees of pressurized water reactors (PWRs) evaluate the reactor vessel beltline materials against specific criteria to ensure protection from brittle fracture. It is not applicable to BWRs such as the MNGP.

2.1.2.4.4 Anticipated Transients without Scram (10 CFR 50.62)

ATWS is a postulated operational transient that generates an automatic scram signal, accompanied by a failure of the Reactor Protection System to automatically shutdown 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 shutdown the reactor following anticipated transients, and to mitigate the consequences of an ATWS event.

For BWRs, the Final ATWS Rule required:

(a) An Alternate Rod Injection (ARI) System, diverse from the Reactor Protection System (RPS), to vent the scram air header automatically under ATWS conditions.

(b) A Recirculation Pump Trip (RPT) System to trip the reactor recirculation (REC) pumps automatically under ATWS conditions.

(c) A SLC System with the capability of inserting negative reactivity equivalent to 86 gpm of 13 weight percent of natural sodium pentaborate decahydrate solution into a 251-inch inside diameter (ID) reactor vessel.

MNGPs system for accommodating ATWS events is described in detail in Section 14.8 of the MNGP USAR.

Plant and vendor drawings, the USAR, initial LR Technical Reports/LRA/SER, docketed correspondence, modifications, and the plant equipment database were reviewed, as applicable, to identify components relied upon to mitigate the ATWS event as part of the systems which comprise the final ATWS Rule. These SSCs are in-scope for SLR.

Recent licensing actions since initial LR, included the analysis and evaluation of various ATWS considerations for EPU, the transition to AREVA fuel, and MELLLA+. Per USAR 14.8 and the associated SERs (References 1.6.17 and ML13316B298), all these analyses resulted in meeting the ATWS acceptance criteria. No additions to scoping were required.

The scoping process to identify systems and structures relied upon and/or specifically committed to for ATWS at MNGP is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.2.4.5 Station Blackout (10 CFR 50.63)

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 SBO (10 CFR 50.63) be included within the scope of SLR.

A SBO event is a complete loss of alternating current (AC) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e., loss of the Offsite Electric Power System concurrent with turbine trip and unavailability of the onsite emergency AC power sources). SBO does not include the assumption of loss of available AC power to buses fed by (1) station batteries through inverters or (2) alternate AC sources, nor does it assume a concurrent single failure or DBA.

At MNGP, the SBO Rule is implemented by methods described in Nuclear Utility Management and Resource Council (NUMARC) 87-00 and RG 1.155. SBO Rule implementation details for the MNGP are described in docketed correspondences, NRC staff SERs, SBO equipment lists, and supporting calculations (CAs). USAR Section 8.12 summarizes the licensing criteria that are the CLB for resolution of this issue at the MNGP.

MNGP chose to use an AC-independent methodology for coping with an SBO. MNGP fits the category of a plant that must cope with a SBO of 4-hour duration.

Components relied on at MNGP to perform an SBO were identified through review of plant-specific SBO calculations, the USAR, initial LR Reports/LRA/SER, plant drawings, modifications, and the plant equipment database, as applicable.

The NRC issued revised staff guidance for LR on April 1, 2002 that directs that the plant portion of the Offsite Power System used to restore offsite power be included in-scope for SLR (NRC ISG-02). To ensure the guidance of ISG-02 was used, a review of one-line drawings and plant procedures, for performing offsite power restoration, was performed. Components (e.g., breakers, switches, transformers, etc.) explicitly identified in offsite power restoration procedures and their interconnections (busses, disconnect switches, etc.) are in-scope for SLR. Offsite sources identified for power restoration, and therefore in-scope for SLR, include the 345 kV, 115 kV, and 13.8 kV offsite sources. Components and commodities in-scope for SLR are those from the plant 13.8 kV and 4.16 kV busses, through and including the interconnecting transformers, disconnect switches, and busses out to and including the switchyard circuit breakers that connect to these offsite sources.

MNGP's response to and coping capabilities for an SBO event were evaluated at EPU conditions. The battery capacity remains adequate to support high pressure coolant injection, and compressed gas capacity exists to support main steam relief valve actuations. The NRC staff confirmed that required condensate inventory for decay heat removal is within the available condensate storage (CST) tank inventory. The NRC staff concluded that MNGP adequately evaluated the effects of EPU on SBO and demonstrated that they will continue to meet the requirements of 10 CFR 50.63. The CST tanks were not originally in-scope for initial LR, but they are within the scope of SLR. SBO response was not affected by any of the other major licensing actions since initial LR.

The scoping process to identify systems and structures relied upon and/or specifically committed to for SBO at MNGP is consistent with and satisfies the associated criterion in 10 CFR 54.4(a)(3).

2.1.3 <u>Information Sources Used for Scoping and Screening</u>

In addition to the MNGP USAR and Technical Specifications, the following additional CLB and other information sources were relied upon to a great extent in performing scoping and screening for MNGP. A brief discussion of these sources is provided. Information used in this SLRA is current as of June 1, 2021.

2.1.3.1 Design Basis Documents

The MNGP DBDs were prepared for several support and accident mitigation systems, selected licensing issues, and USAR Chapter 14 Accident Analyses. The DBDs are a tool to explain the requirements behind the plant design rather than describing the design itself. DBDs are not CLB documents. DBDs are intended to complement information obtained from other sources and to identify potential reference documents.

2.1.3.2 Controlled Plant Component Database

Specific component information for SSCs at MNGP can be found in the controlled component database. The component database contains as-built information on a component level and consists of multiple characteristics for each component, such as design-related information, safety and seismic classifications, safety classification bases, and component tag, type, and description. When safety characteristics of a component are unavailable or not validated, MNGP procedures along with other controlled documents (e.g., USAR, piping and instrumentation diagrams (P&IDs)) can be used to determine the proper characteristics.

2.1.3.3 Plant Drawings

MNGP plant drawings were used as references when performing SSC evaluations for SLR. MNGP P&IDs are color-coded to show various Quality Groups. These drawings and related engineering documents were utilized to determine SSC functional requirements, safety classifications, environments, materials of construction, etc., in support of scoping, screening and AMR evaluations. The drawings were also used to identify any engineering changes that may have impacted the scoping, screening, or AMR at MNGP.

For MNGP mechanical systems, all applicable P&IDs were reviewed to identify the specific system boundaries included in the scope of SLR. These boundaries are also depicted on the SLRBDs. The in-scope boundaries of the mechanical systems are highlighted in color on each SLRBD.

2.1.3.4 Fire Protection Program

The MNGP USAR (specifically Appendix J, *Fire Protection Program*, which includes the SSA and FHA), Technical Specifications, TRM, initial LR Technical Reports/LRA/SER, licensing correspondence, DBDs, and design drawings were used in determining equipment required for support of the Fire Protection (B.2.3.15) program. These documents were used to identify credited FP equipment.

2.1.3.5 Station Blackout Equipment

Equipment relied upon to mitigate a SBO event at MNGP is described in Section 8.12 of the USAR. This USAR section (and references therein) was used to identify components and equipment credited for SBO. In accordance with Section 2.5.2.1.1 of NUREG-2192, the portion of the Offsite Power System that is used to connect the plant to the offsite power source is also included in the SBO scope of SLR.

2.1.3.6 Environmental Qualification Documentation

The MNGP EQ Equipment Master List provides a detailed listing of all equipment and components that must be environmentally qualified for use in a harsh environment. This MNGP Equipment Master List was used to identify equipment that must meet the relevant requirements of 10 CFR 50.49.

2.1.3.7 Operations Manuals

The MNGP Operations Manuals provide a detailed listing of licensing requirements and bases for systems for SSCs at MNGP. This includes the function and general description of the SSC.

2.1.3.8 10 CFR 50.59 Evaluations

10 CFR 50.59 evaluations provide a consolidated location to determine the impact that a modification or other plant change may have on the CLB, a regulated event covered under 10 CFR 54.4(a)(3), or other aspect that may impact the scoping and screening of an SLR SSC.

2.1.3.9 Original License Renewal Documents

Documentation from the initial LRA for MNGP was used as a starting point for the identification of systems and structures within the scope of SLR (Reference 1.6.24). This documentation includes the initial LRA scoping, screening, and AMR reports. The initial LRA reports were reviewed and approved and are still considered Quality records. The following documents were used in when preparing this SLRA:

- Application for Renewed Operating Licenses, Monticello Nuclear Generating Plant (March 2005) and related docketed regulatory correspondence.

- NUREG-1865, Safety Evaluation Report Related to the License Renewal of the Monticello Nuclear Generating Plant (Reference 1.6.25).

2.1.3.10 Other Current Licensing Basis References

Other CLB references utilized in the scoping and screening process include:

- NRC SERs including NRC staff review of MNGP major licensing submittals (including AST) (Reference ML062790015), EPU (References ML13316B298 and ML13343A006), MELLLA+ (Reference 1.6.15), AREVA Fuel and Safety Analysis Methods (Reference 1.6.17), and Extended Flow Window (Reference 1.6.18).

- Licensing correspondence including relief requests, Licensee Event Reports, and responses to NRC communications such as NRC bulletins, generic letters (GLs), or enforcement actions.

- Engineering evaluations, calculations, and engineering change packages which can provide additional information about the requirements of characteristics associated with the evaluated SSCs.

2.1.4 Scoping Methodology

The scoping process is the systematic process used to identify the MNGP SSCs within the scope of SLR. 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 and other design input documents. The system and structure scoping results are provided in Table 2.2-1.

The MNGP scoping process began with the development of a comprehensive list of plant systems and structures, as described in Section 2.1.2.1.

Each MNGP system and structure was then reviewed for inclusion in the scope of SLR using the criteria of 10 CFR 54.4(a). These criteria are as follows:

- Title 10 CFR 54.4(a)(1) – Safety-related

- Title 10 CFR 54.4(a)(2) – Non-safety related affecting safety-related

- Title 10 CFR 54.4(a)(3) – Regulated Events:
    - FP (10 CFR 50.48)
    - EQ (10 CFR 50.49)
    - PTS (10 CFR 50.61)
    - ATWS (10 CFR 50.62)
    - SBO (10 CFR 50.63)

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

In accordance with 10 CFR 54.4(a)(1), SSCs within the scope of LR include:

> *Safety-related systems, structures, and components which are those relied upon to remain functional during the 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*.

SR classifications for systems and structures are based on system and structure descriptions and analysis in the USAR. SR structures are those structures listed in the USAR Chapter 12 and classified as Class 1. Systems and structures identified as SR in the USAR meet the criteria of 10 CFR 54.4(a)(1) and are included within the scope of SLR. SR components in the Functional Location Classification database were also reviewed, and the systems and structures that contained these components were also included within the scope of SLR. The review also confirmed that all plant conditions, including conditions of normal operation, internal events, anticipated operational occurrences, DBAs, external events, and natural phenomena as described in the CLB, were considered for SLR scoping.

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

In accordance with 10 CFR 54.4(a)(2), the SSCs within the scope of LR include:

> *All non-safety 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 NSR SSCs with respect to the following application or configuration categories:

- NSR SSCs that may have the potential to prevent satisfactory accomplishment of safety functions,
- NSR SSCs directly connected to SR SSCs (typically piping systems), and
- NSR SSCs that are not directly connected to SR SSCs but have the potential to affect SR SSCs through spatial interactions.

These categories are discussed in detail below.

The initial MNGP LR 10 CFR 54.4(a)(2) scoping results were used as a starting point for the determination of the SSCs within the scope of 10 CFR 54.4(a)(2) for MNGP SLR. Additional sources of information used to determine this scope includes the initial LR NRC SER NUREG-1865, MNGP USAR, MNGP NRC docketed correspondence, plant design modifications implemented between initial LR and June 1, 2021, and other information sources listed in Section 2.1.3.

Modification Reviews: Modifications/engineering changes that have been completed at MNGP since the initial LR have been reviewed as part of the SLR effort. These modification review results have been examined to determine if any of these completed modifications would have created any additional SSCs meeting the Non-Safety Affecting Safety (NSAS) scoping criteria. In a few cases, NSR components were installed in spaces containing SR equipment. These newly installed NSR components are in-scope of SLR.

2.1.4.2.1 Non-Safety Related SSCs with Potential to Prevent Satisfactory Accomplishment of Safety Functions

This category addresses NSR SSCs that are required to function in support of SLR intended functions of SR SSCs. This functional requirement distinguishes this category from other categories where the NSR SSCs are only required to maintain adequate integrity to preclude structural failure or spatial interaction.

NSR SSCs may have the potential to prevent satisfactory accomplishment of safety functions. For additional guidance, NEI 17-01 refers to the industry guidance documented in NEI 95-10, Appendix F. Items identified in the MNGP CLB where this can occur include the following:

Internal and External Missile Hazards: Missiles that could be generated from internal sources or external sources such as rotating equipment and tornados were evaluated during the design of the plant (USAR Sections 12.2.1.8, 12.2.2.4.3, and 12.2.3). Both preventive (e.g., overspeed controls, seismic restraints) and mitigative (e.g., missile barriers) features were installed to ensure safe shutdown as required by the CLB for postulated missile hazards. These design features were in-scope for initial LR and are also in-scope for SLR.

Cranes/Overhead Handling Systems: Overhead Handling Systems associated with heavy loads as described in NUREG-0612 (Reference 1.6.26) meet the criteria of 10 CFR 54.4(a)(2) and were in-scope for MNGPs initial LR and are also in-scope for SLR (USAR Sections 10.2.6.1 and 12.2.5). Additionally, the refueling platform and fuel preparation machine meet the criteria of 10 CFR 54.4(a)(2) and are in-scope for SLR as they were for initial LR.

<u>Internal and External Flooding Events</u>: Flooding from various internal sources (e.g., pipe breaks) and external sources (e.g., river floods) were evaluated during the design of the plant and via various subsequent licensing actions. Flood protection is discussed in USAR Section 12.2.1.7. Several design features are installed in the plant to ensure safe shutdown as required by the CLB for the specific events evaluated. These features (sump pumps, level switches, flood barriers, pump spray hoods, drain systems, etc.) were in-scope for the initial LR and are in-scope for SLR. Walls, curbs, dikes, doors, etc., that provide flood barriers to SR SSCs are typically evaluated as part of the building structure.

<u>High Energy Line Break (HELB)</u>: The High Energy CLB definition for MNGP is a fluid/system with a normal operating temperature >200°F and a normal operating pressure >275 psig. High energy line breaks outside containment were previously evaluated as documented in Appendix I of the MNGP USAR. With one noted exception, all high-energy lines identified in USAR Appendix I (regardless of safety classification) and their associated in-line components, were included in-scope of the initial LR. This also includes those lines that met the "less than 2% use" exclusion criteria that were not further evaluated in the CLB. The one noted exception is NSR high energy lines located in the Recombiner Building. These lines were excluded from the initial LR scope on the same basis they were excluded from additional consideration in the CLB HELB analysis, i.e., their failure would have no impact on SR SSCs. High energy lines of one-inch diameter or smaller nominal pipe size (NPS) were excluded from the HELB analysis as discussed in the USAR. These small lines were further evaluated and placed in-scope for the initial LR if their failure could adversely affect a SR SSC.

These same descriptions for HELB piping are considered in-scope for SLR. If the HELB piping section met the descriptions listed above, the entire line was included within the scope of SLR, per the industry guidance in NEI 95-10 Appendix F.

HELB related structural components such as whip-restraints and jet impingement shields/barriers, along with the piping supports are in-scope for SLR, consistent with the initial LR (NUREG-1865) and are addressed in the structural area.

<u>Steam Dryer Assembly</u>: Industry OE has shown that steam dryer assembly structural failures can occur, specifically with respect to increased flow/vibration due to power uprates. MNGP replaced their original steam dryer in 2011 with a Westinghouse steam dryer that has been qualified for high-cycle fatigue subject to acoustic loads and it was tested extensively during initial start-up at EPU conditions (USAR Sections 3.6.3 and 12.2.2.17). The steam dryer does not perform a safety function, but it must retain its structural integrity to avoid generation of loose parts that might impact the capability of other SR equipment to perform their safety functions. The steam dryer was in-scope for the initial LR and remains in-scope for SLR.

Offsite Exposure/Alternate Source Term: MNGP implemented Full Scope AST via License Amendment 148, approved by the NRC December 2006. Within this analysis, deposition was credited for main steam lines, main steam bypass lines, associated drain lines, and the condenser. While not classified as SR, these components were determined to be seismically rugged as presented in the SER for AST. These components were in-scope for the initial LR and remain in-scope for SLR.

In addition, several NSR components representing potential leak-paths from the condenser and main steam piping, are included in-scope for SLR due to their potential to affect offsite exposure assumptions.

Neutron Monitoring System Used to Mitigate a Rod Withdrawal Error (RWE): For MNGP, the Rod Block Monitor (RBM) is NSR equipment, and the rod block initiated in response to an RWE is relied upon to stop erroneous withdrawal of a control rod so that local fuel damage does not result (USAR Section 7.2.1.2.2). Local fuel damage does not pose a threat in terms of radioactive material release that could result in off-site exposure comparable to the guidelines of 10 CFR 50.67(b)(2) and therefore, the RBM function of the equipment is not an intended function for SLR. The RBM function is not in-scope for SLR, just as it was not in-scope for the initial LR.

For the initial LR, components associated with the RBM function were evaluated with the Neutron Monitoring System (NMS) due to the overlap in physical proximity, electrical connections, and signal processing. For SLR, passive, long-lived electrical commodities including those associated with the NMS are evaluated during the electrical AMR.

Thermal Insulation to Prevent Excessive Localized Temperatures: All thermal insulation is considered NSR at MNGP. The thermal insulation in-scope of SLR is that which is credited to limit room heat-up in two areas (High Pressure Coolant Injection Room piping insulation and Residual Heat Removal (RHR) Heat Exchanger insulation) and insulation credited for maintaining primary containment hot piping penetrations below temperature limits. Both insulation examples were in-scope for the initial LR.

CST Tanks: The MNGP CST tanks are NSR components. These tanks provide the normal suction source to the High Pressure Coolant Injection System (HPCI). They also are the credited source of water during an SBO event (USAR Section 8.12). Therefore, they are in-scope for SLR.

2.1.4.2.2 Non-Safety Related SSCs Directly Connected to Safety-Related SSCs that Provide Structural Support for the Safety-Related SSCs

Section 4 of Appendix F of NEI 95-10 states that for NSR SSCs that are directly connected to SR SSCs (typically piping systems), the NSR piping and supports, up to and including the first equivalent anchor beyond the safety/non-safety interface, are within the scope of SLR per 10 CFR 54.4(a)(2).

For SLR, MNGP follows the same approach that was used for the initial LR regarding NSR SSCs that are directly connected to SR SSCs. That approach matches the NRC and industry guidance provided in NEI 95-10.

For NSR SSCs directly connected to SR SSCs, the in-scope boundary for SLR extends into the NSR portion of the piping and supports up to and including the first equivalent anchor beyond the safety/non-safety interface. For MNGP, the first equivalent anchor is that point beyond which failure of the NSR piping system will not prevent the satisfactory accomplishment of the SR function of the connected SSCs. Examples that constitute the first equivalent anchor include: a true anchor; a large piece of plant equipment (that large piece of equipment would also be in-scope); a grouted building penetration for small bore piping, where buried pipe exits the ground (using the ground as an equivalent anchor – see response to Request for Additional Information (RAI) 2.1-2 Supplement in NUREG-1865); or at least two supports in each orthogonal direction.

In general, equivalent anchors were selected consistent with the pipe analyses of record that demonstrate seismic adequacy of the various configurations. The piping components and supports up to and including the first equivalent anchor are in-scope for SLR.

The following methods were used to determine end points for the portion of NSR piping attached to SR piping to be included in-scope for SLR for cases where there is no equivalent anchor.

- NSR Branch lines may have been excluded from scope if their mass and stiffness relative to the SR piping was small. In the MNGP piping analysis guidelines, a moment of inertia ratio greater than 40-to-1, the effects of the branch line on the run pipe are considered negligible. An NSR branch pipe meeting this criterion would not need to be in-scope for SLR for impact/support but may need to be considered for spray/leakage.

- Primary Containment Atmospheric Control (PCAC) piping off the torus and drywell transition into ducting. Due to the relative flexibility of the ducting, the NSR ducting was considered to have a negligible impact on the piping, and therefore the NSAS scoping boundary for these lines was at the ducting transition point.

- Small bore vent and drain lines off SR piping or equipment. Typically, the first valve off the main header is SR, and then is NSR thereafter. Many of these have few or no supports on the NSR portion, and in these instances, the entire NSR portion of the line is in-scope for SLR.

- Small bore piping often transitions to tubing. Due to the relative flexibility of the tubing with respect to the piping, the tubing was considered to have a negligible impact on the piping. Therefore, the NSAS boundary would be at the tubing transition point.

These methods are in-line with the industry guidance; the in-scope boundary is at a point such that the out-of-scope NSR piping/components will not render the SR portion of the piping unable to perform its intended function under CLB conditions.

NSR structures attached to, or next to, SR structures are in-scope for SLR if their failure could prevent a SR SSC from performing its intended function.

2.1.4.2.3 Non-Safety Related SSCs that Have the Potential to Affect Safety-Related SSCs through Spatial Interactions

NSR SSCs that are not connected to SR piping or components; or are outside the structural support boundary for the attached SR piping system and have a spatial relationship such that their failure could adversely impact the performance of a SR SSC intended function, must be evaluated for SLR scope in accordance with 10 CFR 54.4(a)(2) requirements. To address this requirement, MNGP has chosen to use the preventative option (i.e., spaces approach) as described in Appendix F to NEI 95-10.

<u>Non-Seismic and Seismic II/I Piping and Supports:</u> Based on the information in NEI 95-10, Appendix F, Section 5.2.2.3, it has been shown that even aged piping systems will not fall as long as their supports stay intact. Therefore, all NSR supports for non-seismic or Seismic II/I piping systems with a potential for spatial interaction with SR SSCs, are included within the scope of SLR. These supports are addressed in a commodity fashion within the civil/structural area review.

<u>Spatial Interactions Identified During Walkdowns for Initial LR</u>: In order to identify spatial interactions that could result in SSCs meeting NSAS criterion, the following approach and criteria were implemented.

A list of SR components and commodities was assembled based on the plant equipment database, drawings, walkdowns and plant knowledge.

A list of rooms containing SR equipment was developed. Since almost every room in an affected structure contained SR equipment (e.g., Reactor Building), all rooms in these structures were listed and walkdowns performed.

Walkdowns were performed of accessible areas. For inaccessible areas during plant operation (due to high radiation), a review using controlled piping layout and other physical configuration drawings was performed. Walkdowns of some of these areas were later performed as allowed by plant operating conditions.

The walkdowns were performed on a spaces approach using a conservative set of walkdown criteria to identify NSAS components. Both spray (pressurized liquid or steam lines) and leaks (non-pressurized liquid lines) were identified and evaluated for their impact on SR components. Spray and leak interactions were evaluated without regard to whether the SR components were active or passive and without regard to the duration of the spray or leak. All pressurized liquid systems in the general area of SR components were considered in-scope for LR and assumed to leak anywhere around the circumference or along the length of the pipe. General area is defined as being on the same floor of a building with no barrier walls between the fluid or steam source and the SR component. All non-pressurized liquid systems directly above SR components were also in-scope for LR. These leaks were assumed to occur anywhere along the length of the piping system. Since all piping supports in buildings with SR components are in-scope for LR, NSR piping systems were not evaluated for fall or impact interactions.

Air and gas systems (non-liquid) are not a hazard to other plant equipment. A plant-specific review was made of OE in regard to air/gas systems which verified that MNGP air/gas systems have not negatively affected other plant equipment. A review of industry OE also failed to reveal any events of this nature. Since none of the air/gas lines are high-energy lines and all supports in buildings with SR components are in-scope for LR, air/gas systems are not in-scope for NSAS with respect to spatial interaction.

A second set of walkdowns for select rooms was performed to further refine initial results. During these additional walkdowns it was confirmed that no SR components were located in these areas or there were no NSR components that could spray or leak on SR components (using the above walkdown criteria). Therefore, some NSR components were eliminated from NSAS considerations.

Since this methodology was reviewed and approved for the initial LR, and the methodology meets the current regulatory and industry guidance for NSAS, the walkdown results from the initial LR remain valid for SLR.

Spatial Interaction Walkdowns and Reviews for SLR: SLR walkdowns were performed on select SR and NSR areas looking for NSR equipment that could potentially impact SR equipment. Results from initial LR were used as a starting point to identify the areas of interest, which was then further refined based on site experience and accessibility. In addition to the walkdowns, select SLR boundary drawings were also reviewed to identify additional areas of interest. As the result of a thorough walkdown and SLR boundary drawing review, additional items were discovered to be within the scope of SLR.

Seismic Interaction: Within the MNGP CLB, some lines and structures designed to Class 2 seismic requirements were reanalyzed to more stringent requirements due to potential adverse interaction with SR SSCs to prevent pipe failure. All of these reanalyzed sections of piping are in-scope of SLR in accordance with 10 CFR 54.4(a)(2), including their associated supports and structures.

NSR Conduits, Trays, Junction Boxes, and Lighting Fixtures**:** NSR conduits, cable trays, junction boxes, lighting fixtures may contain or be routed near SR cables or other components. Therefore, for determining which of these commodities to consider in-scope for LR, a conservative simplified approach is used. All NSR conduits, trays, junction boxes and lighting fixtures and their supports located within structures housing SR equipment are in-scope for SLR. Additionally, conduits, trays, junction boxes and lighting fixtures and their supports required for regulated events that are located in structures not housing SR equipment are in-scope for SLR.

NSR HVAC Ducts and Supports: Though most Heating, Ventilation, and Air Conditioning (HVAC) ducts and their supports are NSR, they are located throughout the plant and typically run along ceilings and thus above many SR SSCs. Similar to air/gas pipe systems, HVAC ducts are not a hazard to other plant equipment. The only spatial interaction concern is falling. Similar to conduit and cable trays, a conservative simplified approach is used. All HVAC duct supports located within structures housing SR components are in-scope for SLR.

2.1.4.2.4 Abandoned Equipment

There are mechanical fluid components at MNGP that have been abandoned in-place, using a site procedure. Abandoned piping components within structures containing SR components were excluded from scope when the following conditions were met:

(1) The abandoned piping components do not provide structural or seismic support to attached SR piping, and

(2) The abandoned piping is separated from sources of water by blanks, blind flanges, pipe caps, or closed valves (if an open drain is available to identify leak-by), and

(3) The abandoned piping is empty of liquid. Piping was verified to be empty by establishing configuration (such as the piping being open-ended at the low point), by review of documents that abandoned the equipment, or by other methods that are capable of confirming the absence of trapped fluid.

The abandoned equipment does not need to be managed for leakage or spray but may need to be managed for potential impact (supports in-scope and managed). This is consistent with the plant "spaces" approach for spatial interaction if SR SSCs are located within the same space. This approach is discussed in Section 2.1.4.2.3.

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

In accordance with 10 CFR 54.4(a)(3), the SSCs within the scope of LR 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).*

With the exception of Pressurized Thermal Shock (not applicable to BWRs), Section 2.1.2.4 identifies the references to source documents used to determine the scope of components within a system that are credited to demonstrate compliance with each of the applicable 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 SLR.

2.1.4.4 System and Structure Intended Functions

For the systems and structures within the scope of SLR, the intended functions that are the bases for including them within the scope are identified during the scoping process and documented in the individual systems and structures screening and AMR technical reports. Intended functions define the plant process or condition that must be accomplished in order to perform or support a critical safety function for responding to a DBE or to perform or support a specific requirement of one or more of the five regulated events in 10 CFR 54.4(a)(3). At the major system/structure level, the intended function may be thought of as the reason a system or structure is included within the scope of SLR. The goal of intended function identification is to provide a basis for determination of SCs requiring an AMR in accordance with 10 CFR 54.21(a). The identification of the specific component/structure intended functions supporting the system's intended function is performed as part of the screening process as described in Section 2.1.5.

2.1.4.5 Scoping Boundary Determination

Systems and structures that are included within the scope of SLR are then further evaluated to determine the populations of in-scope SCs. 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 P&IDs 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 mechanical systems are placed in commodity groups and are screened as commodities. The determination of SLR system and structure boundaries are further described in the screening procedures for mechanical systems (Section 2.1.5.1), civil structures (Section 2.1.5.2), and electrical and I&C systems (Section 2.1.5.3).

2.1.5 Screening Methodology

This section discusses the screening process used at MNGP to determine which structures and components are in the scope of SLR and require an AMR.

The requirement to identify SCs subject to an AMR is specified in 10 CFR 54.21(a)(1):

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.*

For SLR, SCs that perform an intended function without moving parts or without a change in configuration or properties are defined as passive. For SLR, passive SCs that are not subject to replacement based on a qualified life or specified time period are defined as long-lived. The screening procedure is the process used to identify passive, long-lived SCs that are in the scope of SLR and are subject to an AMR.

This portion of the MNGP IPA methodology is divided into three engineering disciplines: mechanical, civil/structural, and electrical/I&C. The relevant aspects of the component/structural component scoping and screening process for mechanical systems, civil structures, and electrical and I&C systems are described in Section 2.1.5.1, Section 2.1.5.2, and Section 2.1.5.3, respectively. A statement regarding how the initial LR boundaries compare to SLR boundaries is included in the "Boundary" discussion in each of the individual systems and structures screening and AMR technical reports. For the systems and structures where the boundaries have not changed, a statement is made that there are no significant differences. The word "significant" is utilized to clarify that there may be minor differences within the boundaries (e.g., valve numbering, locations of vents and drains, etc.,), but that the overall boundaries have not changed for SLR.

For mechanical systems and civil structures, this process establishes evaluation boundaries, determines the SCs that comprise the system or structure, determines which of those SCs support system/structure intended functions, and identifies specific SC intended functions. Consequently, not all the SCs for in-scope systems or structures are within the evaluation boundaries for SLR because they are not in the scope of SLR. Once these in-scope SCs are identified, the screening process then determines which SCs are subject to an AMR per the criteria of 10 CFR 54.21(a)(1).

For electrical and I&C systems, a component/commodity-based approach as described in NEI 17-01 is taken. This approach establishes component/commodity evaluation boundaries, determines the electrical and I&C component commodity groups that compose in-scope systems, identifies specific component and commodity intended functions, and then determines which component commodity groups are subject to an AMR per the criteria of 10 CFR 54.21(a)(1). This approach calls for component/commodity level scoping after screening has been performed.

Table 2.1-1 provides the definitions for component intended functions that are used for screening components and structures.

2.1.5.1 Mechanical Systems

For mechanical systems, the component/structural component screening process is performed on each system identified to be within the scope of SLR. This process evaluates the individual SCs included within in-scope mechanical systems to identify specific SCs or SC groups that require an AMR. Each in-scope mechanical system is evaluated in a screening and AMR technical report. These mechanical systems in the scope of SLR are grouped into one of the following categories:

- Reactor Coolant System (Section 2.3.1)
- Engineered Safety Features (Section 2.3.2)
- Auxiliary Systems (Section 2.3.3)
- Steam and Power Conversion Systems (Section 2.3.4)

Where appropriate, multiple mechanical systems were included in a single screening and AMR technical report. Examples of this include the multiple systems included in Reactor Coolant Pressure Boundary (RCPB) and Connected Piping Screening and AMR technical report and multiple heating and ventilation systems addressed in one Screening and AMR technical report.

Mechanical system evaluation boundaries were established for each system within the scope of SLR. These boundaries were determined by mapping the pressure boundary, leakage boundary, or boundary associated with another component intended function associated with the SLR system intended functions onto the system P&IDs. The SLRBDs highlight all in-scope components, but not all highlighted components may be subject to AMR. SLR system intended functions are the functions a system must perform relative to the scoping criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3). The SLRBDs associated with each mechanical system within the scope of SLR are identified with the mechanical system AMR.

The sequence of steps performed on each mechanical system determined to be within the scope of SLR is as follows:

- Identify all SCs within that system based on design drawings, initial LR documents, and the system component list from the component database.

- Define system evaluation boundaries and eliminate SCs not within the scope of SLR (i.e., not required to perform SLR system intended functions). The system intended function boundaries include those portions of the system that are necessary to ensure that the intended functions of the system are performed.

- Components needed to support each of the SLR system-level intended functions identified in the scoping process must be included within the system intended function boundaries.

- The primary method of designating the system intended function boundaries is to identify the boundaries on system P&IDs. The basis for the boundary is explained in the screening and AMR technical report.

- The Screening process will then identify SCs that perform their intended functions in a passive manner and thus allow elimination of all active SCs. Valve bodies, fan housings and pump casings may perform an intended function by maintaining the system pressure boundary and, therefore, would be subject to AMR.

- Identify long-lived SCs that allow for elimination of all short-lived (routinely replaced) SCs. The long-lived/short-lived determination is only required for those SCs that are within the scope of SLR. If the component is not subject to replacement based on a qualified life or specified time period, then it is considered long-lived. Components that are not long-lived do not require an AMR.

- Components within the system intended function boundaries that are both passive and long-lived are identified as subject to AMR in each of the mechanical system screening and AMR technical report.

MNGP ensures building temperatures are maintained within normal operating EQ design limits and takes specific corrective action if a condition occurred that would challenge those temperatures. Additionally, adverse localized environments (ALEs) are addressed as part of the Environmental Qualification of Electric Equipment AMP (Section B.2.2.3), the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (Section B.2.3.36), and the Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrument Circuits AMP (Section B.2.3.37).

Some mechanical components are considered complex assemblies. A complex assembly is a predominantly active assembly where the performance of its components is closely linked to the intended function of the entire assembly, such that testing, and monitoring of the assembly is sufficient to identify degradation of the component. Examples of complex assemblies at MNGP include the emergency diesel generators (EDGs), and air compressors. 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 AMR. The boundaries identified for each complex assembly are detailed in their respective screening and AMR technical reports. This follows the screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192.

2.1.5.2 Civil Structures

For structures, the screening process is performed on each structure identified to be within the scope of SLR consistent with initial LR. This method evaluates the SCs included within in-scope structures to identify SCs or SC groups (commodities) that are subject to an AMR. Each in-scope structure and SC is evaluated in a screening and AMR technical report. The structures in the scope of SLR are grouped into one of the following categories:

- Containment Building Structure

- Plant Structures

The sequence of steps performed on each structure determined to be within the scope of SLR is as follows:

- Based on a review of design drawings, the structure list from the USAR, and initial LR documents, SCs that are included within the structure are identified. These SCs include items such as walls, floors, foundations, supports, and electrical and I&C components, (e.g., conduit, cable trays, electrical enclosures, instrument panels, and related supports).
- The SCs that are within the scope of SLR (i.e., required to perform a SLR system intended function) are identified.
- Design features and associated SCs that prevent potential seismic interactions for in-scope structures housing both SR and NSR systems are identified.
- Component intended functions for in-scope SCs are identified. The component intended functions identified are based on the guidance of NEI 17-01.
- The in-scope SCs that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) are identified.
- The passive, in-scope SCs that are not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) are identified as requiring an AMR.
- In-scope structural components/commodities that are both passive and long-lived are identified as subject to AMR in each of the structural Screening and AMR technical reports.

2.1.5.3 Electrical and Instrumentation & Control Systems

The method used to determine which electrical and I&C components are subject to an AMR is organized based on component commodity groups. The primary difference in this method versus the one used for mechanical systems and civil structures is the order in which the component scoping and screening steps are performed. This method was selected for use with the electrical and I&C components since most electrical and I&C components are active. Thus, this method provides the most efficient means for determining electrical and I&C components that require an AMR. The method employed is consistent with the guidance in NEI 17-01. All electrical and I&C commodity groups are evaluated within a single Screening and AMR report – Electrical Systems.

The sequence of steps for identification of electrical and I&C components that require an AMR is as follows:

- Electrical and I&C component commodity groups associated with electrical, I&C, and mechanical systems within the scope of SLR are identified. This step includes a review of design drawings and electrical and I&C component commodity groups in the initial LR documents.

- A description and function for each of the electrical and I&C component commodity groups are identified.
- The electrical and I&C component commodity groups that perform an intended function without moving parts or without a change in configuration or properties (screening criterion of 10 CFR 54.21(a)(1)(i)) are identified.
- For the passive electrical and I&C component commodity groups, component commodity groups that are not subject to replacement based on a qualified life or specified time period (screening criterion of 10 CFR 54.21(a)(1)(ii)) are identified as requiring an AMR. Electrical and I&C component commodity groups covered by the 10 CFR 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants* , are considered to be subject to replacement based on qualified life.
- Certain passive, long-lived electrical and I&C component commodity groups that do not support SLR system intended functions are eliminated.

2.1.5.4 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 SLR. A component intended function is defined as specific component functions, performed by passive long-lived components and structural elements, that support system and structure intended functions. Examples of component intended functions are maintain pressure boundary, support SR equipment, and insulate electrical conductors. SCs may have multiple intended functions. MNGP has considered multiple intended functions where applicable, consistent with the staff guidance provided in Table 2.1-3 of NUREG-2192.

Table 2.1-1 provides expanded definitions of structure and component passive intended functions identified for the MNGP SLR project. The table below is based on Tables 2.1-4 and 2.1-5 in NUREG-2192.

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Absorb Neutrons	Absorb neutrons
Direct Flow	Provide spray shield or curbs for directing flow (e.g., safety injection flow to containment sump)

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Electrical Continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals
Emergency Cooling Water Source	Provide source of cooling water for plant shutdown
Filter	Provide filtration
Fire Barrier	Provide rated fire barrier to confine or retard a fire from spreading between adjacent areas of the plant
Flood Barrier	Provide flood protection barrier for internal or external flooding
Heat Sink	Provide heat sink during SBO or design basis accidents
Heat Transfer	Provide heat transfer
HELB Barrier	Provide shielding against HELBs
Holdup and Plateout	Provide post-accident containment, plateout of iodine and holdup (for radioactive decay) of iodine and non-condensable gases before release.
Insulate (electrical)	Insulate and support an electrical conductor
Insulate (thermal)	Inhibit/prevent heat transfer across a thermal gradient
Insulation Jacket Integrity	Prevent moisture absorption and provide physical support of thermal insulation.

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Leakage Boundary	NSR components that maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of SR SSCs
Maintain Adhesion	Provides adhesion to the substrate. This intended function applies to coatings.
Mechanical Closure	Provide closure of components. Typically used for non-structural bolting.
Missile Barrier	Provide missile barrier (internally or externally generated)
Pipe Whip Restraint	Provide pipe whip restraint
Pressure Boundary	Provide pressure-retaining boundary or essentially leak tight barrier 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
Shelter, Protection	Provide shelter/protection to in-scope components
Shielding	Provide shielding against radiation
Spray	Convert fluid into spray
Structural Integrity (Attached)	NSR components that maintains mechanical and structural integrity to provide structural support to attached SR SSCs
Structural Support	Provide structural and/or functional support to SR and/or NSR components. This intended function is also typically used for structural bolting and component supports.

Table 2.1-1
Passive Structure/Component Intended Function

Intended Function	Definition
Throttle	Provide flow restriction

2.1.5.5 Stored Equipment

The MNGP CLB does credit stored equipment that procedures require to be installed during external events or other emergency or abnormal conditions.

- Steel plates dedicated for external flooding events
- Steel hatch covers dedicated for external flooding events
- Portions of bin wall (not normally installed) for external flooding

These are in-scope for SLR and require aging management as shown in Table 2.4-9.

2.1.5.6 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 SLR: (1) packing, gaskets, component seals and O-rings; (2) structural sealants; (3) oil, grease, and component filters; (4) system filters, fire extinguishers, fire hoses, and air packs.

- Group (1) subcomponents (packing, gaskets, component seals, and O-rings): Per NUREG-2192, Table 2.1-3, these consumables are considered subcomponents and are not explicitly called out in scoping and screening procedures. They are included at the component level (i.e., seals for in-scope valves are included as subcomponents of said valves). These subcomponents are not relied upon for the performance of any SLR intended functions under 10 CFR 54; therefore, these items are not considered within the scope of SLR and are not subject to an AMR.

- Group (2) structural sealants: Structural sealants are treated as subcomponents of their associated structure. These consumables are not called out explicitly in scoping and screening and are implicitly addressed in the AMP for Structures.

- Group (3) subcomponents (oil, grease, and component filters): Subcomponents in this group are short-lived and periodically replaced. Various plant procedures are used in the replacement of oil, grease, and filters in components that are in the scope of SLR. As these subcomponents are not considered long- lived, they are not subject to an AMR.

- Group (4) consumables (system filters, fire extinguishers, fire hoses, and air packs): system ventilation filters, fire extinguishers, fire hoses, nitrogen (N_2) cylinders, halon cylinders, and air packs are within the scope of SLR but are not subject to aging management because they are replaced based on measured degradation in performance or condition replacement criteria specified in applicable NFPA codes, technical specifications, or site approved programs as described in the FIR System AMR.

2.1.6 Interim Staff Guidance Discussion

As discussed in NEI 17-01, the NRC has encouraged applicants to address SLR-ISG documents in the SLRA. The following SLR-ISGs have been issued for use:

- SLR-ISG-2021-01-PWRVI Updated Aging Management Criteria for Reactor Vessel Internal Components for PWRs (Reference ML20217L203). This is not applicable to MNGP (BWR).
- SLR-ISG-2021-02-MECHANICAL Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance (Reference ML20181A434)
- SLR-ISG-2021-03-STRUCTURES Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance (Reference ML20181A381)
- SLR-ISG-2021-04-ELECTRICAL Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance (Reference ML20181A395)

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

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

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

- X.M2, *Neutron Fluence Monitoring*

  The AMP was revised to reference approaches that have been found to be acceptable in recent staff reviews of extended beltline and RVI fluence calculations, as RG 1.190 (Reference 1.6.27) is not applicable.

- XI.M2, *Water Chemistry*

  The AMP and USAR Supplement are revised to include the latest revision of Electric Power Research Institute (EPRI) guidelines for BWRs and PWRs.

- XI.M12, *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)*

  This AMP was revised to add the 2019 Edition of American Society of Mechanical Engineers (ASME) Code, Section XI, Non-mandatory Appendix C, which provides flaw evaluation procedures for cast austenitic stainless steel (CASS) with ferrite content ≥ 20 percent.

- XI.M21A, *Closed Treated Water System*

  The AMP was revised to include the latest revision of EPRI closed cooling water chemistry guidelines.

- XI.M26, *Fire Protection*

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

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

  The SLR-ISG revises NUREG-2191, Table VII.H2, "Emergency Diesel Generator System" and makes conforming changes to NUREG-2192, Table 3.3-1 to include line items to manage the reduction of heat transfer for a steel heat exchanger radiator exposed internally to diesel fuel oil and include a line item for managing loss of material for nickel alloy externally exposed to diesel fuel oil.

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

  The AMP was revised to recommend opportunistic inspections, in lieu of periodic inspections, as an acceptable alternative for buried internally coated/lined fire water piping if certain conditions are met.

The guidance in this SLR-ISG is evaluated and incorporated (as applicable) in the respective AMPs as described in Appendix B.

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

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

- XI.S8, *Protective Coating Monitoring and Maintenance*

  The AMP revises the frequency of inservice coating inspection monitoring to no later than 6 years based on trending of the total amount of permitted degraded coatings and adopts Revision 3 to RG 1.54 (Reference 1.6.28).

- NUREG-2192, Section 3.5, *Fatigue Waiver*

  An option is provided to perform a further evaluation based on ASME Code, Section III, Division 1, Subsection NE, fatigue waiver analysis for containment metallic pressure-retaining boundary components that are subject to cyclic loading but have no CLB fatigue analysis. If the ASME Code fatigue waiver acceptance criteria are met then cracking due to cyclic loading does not require aging management.

- NUREG-2191 and NUREG-2192

  NUREG-2191, Chapters II and III and NUREG-2192, Table 3.5-1 are modified to reflect the option of using plant-specific enhancements to GALL-SLR XI.S6 Structures Monitoring AMP to manage effects of aging in concrete in lieu of recommended plant-specific AMPs. Further evaluation and AMR lines are provided in Section 3.5, *Aging Management of Containments, Structures and Component Supports*. Note that while the ASME Section XI, Subsection IWL AMP is not applicable to MNGP, the Structures Monitoring AMP is applicable and will manage effects of aging in concrete.

The guidance in this SLR-ISG is evaluated and incorporated (as applicable) in the respective AMPs as described in Appendix B.

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

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

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

  The proposed revisions to XI.E3A/B/C allow for a 5-year inspection of manholes with water level monitoring and alarms that result in consistent, subsequent pump out of accumulated water prior to wetting or submergence of cable, as supported by plant OE. Also, the inspection of manholes following event-driven occurrences such as heavy rain, rapid thawing of ice and snow, or flooding, is only recommended when water level monitoring indicates water is accumulating.

- XI.E7, High Voltage Insulators

  The proposed revision to XI.E7 adds polymer and toughened glass high-voltage insulators to the scope and program elements and includes all insulators operating at or above 1 kV.

The guidance in this SLR-ISG is evaluated and incorporated (as applicable) in the respective AMPs as described in Appendix B.

2.1.7 Generic Safety Issues

In accordance with the guidance in NEI 17-01 and NUREG-2192, review of NRC generic safety issues (GSIs) as part of the SLR process is required to satisfy a finding per 10 CFR 54.29. GSIs designated as unresolved safety issues (USIs) and High and Medium-priority issues in NUREG-0933 (Reference 1.6.29), Appendix B, that involve aging effects for SCs subject to an AMR or TLAA evaluations, are to be addressed in the SLRA. The following GSIs were reviewed to assure they did not involve aging effects for SCs subject to an AMR or TLAA evaluations.

Issue 186, Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants involves issues related to crane design and operation. Aging effects are not central to these issues. Additionally, this issue does not involve TLAA evaluations, including typical crane-related TLAAs such as cyclic loading analyses. This issue is now closed (Reference ML113050589).

Issue 189, Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Combustion during a Severe Accident, is not applicable to MNGP, which does not have an ice condenser containment. This issue is now closed (Reference ML13190A244).

Issue 191, Assessment of Debris Accumulation on PWR Sump Performance, addresses the potential for blockage of containment sump strainers that filter debris from cooling water supplied to the safety injection and containment spray pumps following a postulated Loss-of-Coolant-Accident (LOCA). This issue is not applicable to MNGP (BWR).

Issue 193, BWR Emergency Core Cooling Systems (ECCS) Suction Concerns, addresses the possible failure of low-pressure ECCSs due to unanticipated, large quantities of entrained gas in the suction piping from suppression pools in BWR Mark I containments. This issue is not specific to aging management nor TLAAs. The Generic Issues Review Panel completed its assessment and concluded that the issue did not warrant any further regulatory actions. The staff has closed out the GSI (Reference ML16082A288).

Issue 199, Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States, 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. (Reference ML101970221).

Issue 204, Flooding of Nuclear Power Plant Sites Following Upstream Dam Failures, addresses potential flooding effects from upstream dam failure(s) on nuclear power plant sites, spent fuel pools (SFPs), and sites undergoing decommissioning with spent fuel stored in SFPs. Aging effects are not central to this issue. This issue does not involve TLAAs. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan Near Term Task Force (NTTF) Recommendations (Reference ML16102A368).

Thus, there are no GSIs involving aging effects for SCs subject to an AMR or TLAA evaluations that are relevant to the MNGP SLR process.

2.1.8 Conclusion

The scoping and screening methods described in Sections 2.1.4 and 2.1.5 above were used for the MNGP SLR IPA to identify the SSCs that are within the scope of SLR and require an AMR. These methods are consistent with and satisfy the requirements of 10 CFR 54.4, 10 CFR 54.21(a)(1), and 10 CFR 54.21(a)(2).

2.2 PLANT LEVEL SCOPING RESULTS

MNGPs IPA methodology consists of scoping, screening, and AMRs. Table 2.2-1 lists the MNGP systems, structures and commodity groups that were evaluated to determine if they were within the scope of SLR, using the methodology described in Section 2.1. A reference to the section of the SLRA that contains the scoping and screening results is provided for each in-scope mechanical system, structure, and electrical system in the table.

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	Initial LRA System Name	In-scope for SLR	Section
Reactor Coolant System			
Reactor Pressure Vessel	Reactor Pressure Vessel (RPV)	Y	2.3.1.1
Reactor Pressure Vessel Internals	Reactor Pressure Vessel Internals (RIT)	Y	2.3.1.2
RCPB and Connected Piping	Automatic Pressure Relief (APR)	Y	2.3.1.3
	Reactor Vessel Instrumentation	Y	2.3.1.3
	Reactor Head Vent (RHV)	Y	2.3.1.3
	Reactor Recirculation (REC)	Y	2.3.1.3
Engineered Safety Features			
Combustible Gas Control	Combustible Gas Control (CGC)	N	N/A
Core Spray	Core Spray (CSP)	Y	2.3.2.1
High Pressure Coolant Injection	High Pressure Coolant Injection (HPCI)	Y	2.3.2.2
Primary Containment Mechanical	Primary Containment Mechanical (PCM)	Y	2.3.2.3
Reactor Core Isolation Cooling	Reactor Core Isolation Cooling (RCI)	Y	2.3.2.4
Residual Heat Removal	Residual Heat Removal (RHR)	Y	2.3.2.5
Secondary Containment (SCT)	Secondary Containment Mechanical	Y	2.3.2.6
Auxiliary Systems			
Alternate Nitrogen	Alternate Nitrogen (AN2)	Y	2.3.3.1
Chemistry Sampling	Biocide Injection (BIS)	N	N/A
	Hydrogen Water Chemistry (HWC)	N	N/A
	Chemistry Sampling (CHM)	Y	2.3.3.2
Circulating Water	Circulating Water (CWT)	Y	2.3.3.3
Control Rod Drive	Control Rod Drive (CRD)	Y	2.3.3.4
Demineralized Water	Demineralized Water (DWS)	Y	2.3.3.5
Emergency Diesel Generators	Emergency Diesel Generators (DGN)	Y	2.3.3.6
Emergency Filtration Train	Emergency Filtration Train (EFT)	Y	2.3.3.7
Emergency Service Water	Emergency Service Water (ESW)	Y	2.3.3.8
Fire System	Fire (FIR)	Y	2.3.3.9

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	Initial LRA System Name	In-scope for SLR	Section
Fuel Pool Cooling and Cleanup	Fuel Pool Cooling and Cleanup (FPC)	Y	2.3.3.10
Heating and Ventilation	Drywell Atmosphere Cooling (DAC)	N	N/A
	Heating and Ventilation (HTV)	Y	2.3.3.11
	Heating Boiler (HTB)	N	N/A
Instrument and Service Air	Service Air Blower (SAB)	N	N/A
	Instrument and Service Air (AIR)	Y	2.3.3.12
Radwaste Solid and Liquid	Radwaste Solid and Liquid (RAD)	Y	2.3.3.13
Reactor Building Closed Cooling Water	Reactor Building Closed Cooling Water (RBC)	Y	2.3.3.14
Reactor Water Cleanup	Reactor Water Cleanup (RWC)	Y	2.3.3.15
Service and Seal Water	Service and Seal Water (SSW)	Y	2.3.3.16
Standby Liquid Control	Standby Liquid Control (SLC)	Y	2.3.3.17
Wells and Domestic Water	Wells and Domestic Water (WDW)	Y	2.3.3.18
Steam and Power Conversion Systems			
Condensate Storage	Condensate Storage (CST)	Y	2.3.4.1
Condensate and Feedwater	Condensate and Feedwater (CFW)	Y	2.3.4.2
Main Condenser	Main Condenser (CDR)	Y	2.3.4.3
Main Steam	Main Steam (MST)	Y	2.3.4.4
Off-Gas	Off-Gas Holdup and Recombiner (ORS)	Y	2.3.4.5
Turbine Generator	Turbine Generator (TGS)	Y	2.3.4.6
Containments, Structures, and Component Supports			
Primary Containment	Primary Containment (PCT)	Y	2.4.1
Plant Structures and Commodities	Cooling Towers (CLT)	N	N/A
	Cranes, Heavy Loads, Rigging (CRN)	Y	2.4.2
	Diesel Fuel Oil Transfer House (FOH)	Y	2.4.3
	Discharge Structure (DCS)	N	N/A
	Emergency Diesel Generator Building (DGB)	Y	2.4.4
	Emergency Filtration Train Building (EFB)	Y	2.4.5
	Fire Protection Barrier and Commodity Group (FPB)	Y	2.4.6
	Hangers and Supports Commodity Group (HGR)	Y	2.4.7
	HPCI Building (HPB)	Y	2.4.8
	Hydrogen Storage Building (HSB)	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	Initial LRA System Name	In-scope for SLR	Section
Plant Structures and Commodities (Cont.)	Intake Structure (INS)	Y	2.4.9
	Misc. Non-Safety Related Buildings and Structures (MNS)	N	N/A
	Misc. SBO Yard Structures (MSS)	Y	2.4.10
	Non-Essential Diesel Generator Building (NDB)	N	N/A
	Off-Gas Stack (OGS)	Y	2.4.11
	Off-Gas Storage and Compressor Building (OGB)	Y	2.4.12
	Outboard MSIV Air Supply Building (MSB)	N	N/A
	Plant Control and Cable Spreading Structure (PAB)	Y	2.4.13
	Radioactive Waste Building (RWB)	Y	2.4.14
	Reactor Building (RB)	Y	2.4.15
	Scale Inhibitor Building (SIB)	N	N/A
	Screen House (SCH)	N	N/A
	Sodium Hypochlorite Building (SHB)	N	N/A
	Structures Affecting Safety (SAS)	Y	2.4.16
	Turbine Building (TGB)	Y	2.4.17
	Underground Duct Bank (UDB)	Y	2.4.18
Electrical and I&C Systems			
Electrical	480V Station Auxiliary (480)	Y	2.5.1
	4.16 kV Station Auxiliary (4 kV)	Y	2.5.1
	Alternate Shutdown (ASD)	Y	2.5.1
	Annunciators (ANN)	Y	2.5.1
	Cathodic Protection (CAT)	N	N/A
	Communications (COM)	Y	2.5.1
	Computer (CMP)	N	N/A
	DC Battery (DCC)	Y	2.5.1
	Lighting (LTG)	Y	2.5.1
	Meteorology (MET)	N	N/A
	Neutron Monitoring (NMS)	Y	2.5.1
	Non-Essential Diesel Generator (NDG)	N	N/A
	Off Site Power (OSP)	Y	2.5.1
	Plant Protection (PPS)	Y	2.5.1
	Radiation Monitoring (RMS)	Y	2.5.1
	Reactor Level Control (RLC)	Y	2.5.1
	Reactor Manual Control (RMC)	N	N/A
	Rod Position Information (RPI)	N	N/A

Table 2.2-1
Plant Level Scoping Report Results

SLRA System Name	Initial LRA System Name	In-scope for SLR	Section
Electrical (Cont.)	Rod Worth Minimizer (RWM)	N	N/A
	Security (SEC)	N	N/A
	Seismic Monitoring (SMC)	N	N/A
	Traversing Incore Probe (TIP)	N	N/A
	Uninterruptible AC (UAC)	Y	2.5.1

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL SYSTEMS

The scoping and screening results for mechanical systems consist of lists of components and component groups that require AMR, then are grouped, and presented on a system basis. Brief descriptions of mechanical systems within the scope of SLR are provided as background information. Mechanical system intended functions are provided for in-scope systems. For each in-scope system, components or component groups requiring an AMR are provided.

The mechanical scoping and screening results are provided in four sections:

- Reactor Coolant System (2.3.1)
- Engineered Safety Features (2.3.2)
- Auxiliary Systems (2.3.3)
- Steam and Power Conversion Systems (2.3.4)

2.3.1 Reactor Coolant System

2.3.1.1 Reactor Pressure Vessel

Description

The RPV System consists of the RPV top head enclosure, vessel shell, nozzles, nozzle safe ends, penetrations, bottom head, and support skirt and attachment welds. RPV internals are included in the Reactor Pressure Vessel Internals (RIT) System. The RPV serves as a high integrity barrier against leakage of radioactive materials to the drywell and is a part of the reactor coolant pressure boundary (RCPB).

Boundary

Boundaries between the RPV and associated systems and components are typically drawn at the RPV interface. The evaluation boundaries for the RPV typically extend to the nozzle safe ends.

The RPV System boundaries are shown on the following SLRBDs:

SLR-36241
SLR-36241-1
SLR-36242
SLR-36242-1
SLR-36246
SLR-36247
SLR-36248
SLR-36249
SLR-36250
SLR-36251
SLR-36252
SLR-36253
SLR-91197
SLR-96042-1

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The RPV contains and supports the reactor core, the reactor internals, jet pumps, and the reactor core coolant moderator, and maintains proper alignment of the reactor core, control rods and control rod drives.

(2) Maintain pressure boundary. Portions of the RPV System are connected to, and part of, the RCPB during plant operation.

(3) The RPV provides fission product retention capability.

(4) The RPV contains and provides steam for direct use by the ECCS turbine driven pumps.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

None.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP, EQ, ATWS, and SBO.

USAR References

Section 4.2

Components Subject to AMR

Table 2.3.1-1 lists the RPV system component types that require AMR and their associated component intended functions.

Table 3.1.2-1 provides the results of the AMR.

Table 2.3.1-1
Reactor Pressure Vessel Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bottom Head	Pressure Boundary
Control Rod Drive Return Line Nozzle	Pressure Boundary
Head Spray Cap	Pressure Boundary
Nozzle Safe Ends[1]	Pressure Boundary
Nozzle Safe Ends and Flanges[1]	Pressure Boundary
Nozzles[1]	Pressure Boundary
Nozzles: Feedwater	Pressure Boundary
Reactor Vessel Components with Fatigue Analysis	Pressure Boundary Structural Support

Table 2.3.1-1
Reactor Pressure Vessel Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Reactor Vessel Shells, Nozzles, and Welds in the Beltline Region of the Reactor Vessel	Pressure Boundary
Support Skirt and Attachment Welds	Structural Support
Top Head	Pressure Boundary
Top Head Instrument Nozzle Flange	Pressure Boundary
Vessel Head Closure Studs and Nuts	Mechanical Closure
Vessel Penetrations[1]	Pressure Boundary
Vessel Shell and Welds	Pressure Boundary
Vessel Shell Attachment Welds	Structural Support

[1]These component types represent component groups rather than individually citing each component which was done in the MNGP initial LRA.

2.3.1.2 Reactor Pressure Vessel Internals

Description

The RIT System consists of all the SCs within the reactor vessel that provide support for the core, control rod system support, instrumentation support, steam quality enhancement and direct coolant flow.

The portions of the RIT system containing components subject to an AMR include the core shroud and core plate; top guide; core spray lines and spargers; jet pump assemblies; fuel support CRD assemblies; and instrument housings including instrumentation dry tubes. The nuclear fuel is in the RIT system, although it does not require aging management since the fuel is periodically replaced thereby making it short-lived.

Boundary

There are no boundary drawings for this system.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The RIT system provides structural support to maintain core geometry, provide control rod guidance and support, and support the inner vessel instrumentation.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP, ATWS, and SBO.

USAR References

Section 3.6

Components Subject to AMR

Table 2.3.1-2 lists the RIT System component types that require AMR and their associated component intended functions.

Table 3.1.2-2 provides the results of the AMR.

Table 2.3.1-2
Reactor Vessel Internals System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Access Hole Covers (Welded)	Direct Flow
Control Rod Drive Housing	Structural Support
Control Rod Guide Tube and Base	Structural Support
Control Rod Guide Tube Base	Structural Support
Core Plate and Core Plate Bolts	Structural Support
Core Shroud (Upper, Central, Lower)	Direct Flow Structural Support
Core Spray Lines and Spargers; Headers, Spray Rings, Thermal Sleeves	Direct Flow
Core Spray Lines and Spargers; Spray Nozzles	Spray
Core Spray Lines and Spargers; Piping Supports, Clamp Modification	Structural Support
Intermediate Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, Incore Flux Monitor Dry Tubes	Pressure Boundary
Jet Pump Assembly Castings; Elbow, Collar, Flare, Flange, Transition Piece	Direct Flow
Jet Pump Assembly; Holddown Beams	Structural Support
Jet Pump Assembly; Holddown Beam Bolts	Mechanical Closure
Jet Pump Assembly; Riser Brace Arm	Structural Support
Jet Pump Assembly; Riser Pipe, Diffuser, Inlet Elbow, Inlet Header, Mixing Assembly, Thermal Sleeve, Elbow, Collar, Flare, Flange, Transition Piece	Direct Flow
Jet Pump Wedge Surfaces	Structural Support
Low Power Range Monitor Dry Tubes	Pressure Boundary

Table 2.3.1-2
Reactor Vessel Internals System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Orificed Fuel Support	Structural Support Throttle
Reactor Vessel Internals Components	Direct Flow Mechanical Closure Pressure Boundary Spray Structural Support Throttle
Reactor Vessel Internals Components Subject to Fatigue	Direct Flow Mechanical Closure Pressure Boundary Spray Structural Support Throttle
Shroud Support Structure; Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs	Direct Flow Structural Support
Standby Liquid Control Distribution Pipe	Direct Flow Pressure Boundary
Steam Dryer	Structural Integrity (Attached)
Top Guide	Direct Flow Structural Support

2.3.1.3 Reactor Coolant Pressure Boundary and Connected Piping

Description

The RCPB and Connected Piping System comprises the following systems:

- REC System
- RHV System
- APR System
- Reactor Vessel Instrumentation System

The RCPB and Connected Piping System also comprises portions of other systems connected to the pressure vessel consisting of Class 1 piping extending to the outboard isolation valve or to the first anchor point outside containment. The connected systems include the following:

- RHR
- CSP
- HPCI
- RCIC
- RWC
- SLC

- CFW
- MST

While the RPV and the RIT Systems are within the scope of this system, they are addressed separately in Sections 2.3.1.1 and 2.3.1.2 respectively.

The Reactor Recirculation System forces water through the reactor core to provide forced convection cooling of the reactor core. The system consists of two recirculation pump loops outside the vessel and twenty jet pumps inside the vessel. The jet pumps are part of the RIT System, however, the connected flow instrumentation outside of the reactor vessel are included in the Reactor recirculation System. Each recirculation loop outside the vessel consists of a motor-driven recirculation pump, two motor operated gate valves for pump isolation, piping, and required recirculation flow measurement devices. Each recirculation pump is connected to a separate variable frequency motor-generator set which provides variable frequency power supply speed regulation to control the water flow rate and subsequently the reactor power level.

The RHV System vents the reactor pressure vessel during filling for hydrostatic tests and remote venting of non-condensable gases that may accumulate in the vessel head space.

RCPB and Connected Piping System maintains overpressurization protection and automatic depressurization capability for the reactor pressure vessel through the APR System and Automatic Depressurization System (ADS). The APR System is designed to prevent overpressurization during Modes I and II and to provide depressurization during DBEs. Two safety relief valves (SRVs) on each of the four steam lines are equipped to automatically open and blow down the reactor on low RPV level and/or RCS pressure. During the blow down, steam is passed through the valves, down a tailpipe, and through the Torus vent headers to discharge underwater through T-quenchers. ADS provides backup to the HPCI System for RCS inventory control in that it is designed to reduce reactor vessel pressure thereby permitting the use of the alternate shutdown cooling method (ASCM), particularly during a LOCA. Once the reactor is depressurized below the shutoff head of the pump, a core spray pump or an RHR pump is then used to flood the vessel. Safety/relief valves are then used to discharge the heated reactor water to the suppression pool and decay heat is removed to the ultimate heat sink via the RHR heat exchangers.

The RCPB and Connected Piping System includes the Reactor Vessel Instrumentation System which is designed to fulfill the following:

(a) Provide the operator with sufficient information in the control room to protect the vessel from undue stresses.

(b) Provide information which can be used to assure that the reactor core remains covered with water and that the steam separators are not flooded.

(c) Provide redundant, reliable inputs to the RPS to shut the reactor down when fuel damage limits are approached.

(d) Provide a method of detecting leakage from the reactor vessel head flange.

The Reactor Vessel Instrumentation System also includes the reference leg backfill subsystem. This subsystem provides a constant backfill of water from the CRD System's charging water header to the safeguards and feedwater (FW) reference legs to flush any gas-laden water through the condensate chambers and back to the reactor vessel to eliminate level errors due to the degassing phenomenon.

RCPB and Connected Piping System is connected to the reactor vessel and is part of the RCPB. As such, RCPB System pressure-retaining components, including recirculation pump casings, valve bodies, piping, the reactor head vent line, etc., are SR and in-scope of SLR.

Boundary

The in-scope portion of the RCPB and Connected Piping System includes the primary recirculation loops, the reactor pressure vessel, and includes several interconnected systems including portions of the RHV, Reactor Vessel Instrumentation, and APR Systems. Where the RCPB interfaces with other systems, the system boundary is drawn outside the Class 1 to Class 2 break such that all Class 1 components are included in the RCPB.

The interfaces between the RCPB and Connected Piping System and other systems can be seen on the SLRBDs.

SLR-36049-10
SLR-36049-12
SLR-36241
SLR-36241-1
SLR-36242
SLR-36242-1
SLR-36243
SLR-36243-1
SLR-36244
SLR-36247
SLR-36248
SLR-36249
SLR-36251
SLR-36254
SLR-96042-1

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Portions of the RCPB and Connected Piping System are connected to, and part of, the RCPB during plant operation to maintain the pressure boundary.

(2) The RCPB and Connected Piping System provides PCT isolation for those portions of the system that interface with the primary containment.

(3) The RCPB and Connected Piping System provides flow paths for RHR Low Pressure Coolant Injection (LPCI) System, Feedwater, Core Spray, HPCI, RCI, and SLC.

(4) The RCPB and Connected Piping System provides reactor pressure and level indications during operation and post-accident conditions.

(5) The RCPB and Connected Piping System provides overpressure protection. The APR System prevents over pressurization of the RCS. The valves shall open (self-activated) to limit the pressure rise.

(6) The RCPB and Connected Piping System provides a backup to the HPCI System, in the event of HPCI malfunction, for automatically depressurizing the reactor vessel for small breaks in the RCS in time for LPCI or CSP to prevent fuel clad melting.

(7) The RCPB and Connected Piping System provides Low-Low Set System logic which automatically functions to minimize the possibility of an SRV reopening with an elevated water leg in its discharge line.

(8) The SRVs discharges heated reactor water to the torus in support of the ASCM. This supports comparison of MNGP to the guidelines of RG 1.139.

(9) Class 1 portions of the MST System included in the scope of the RCPB and Connected Piping System limit reactor vessel water loss in the case of a main steam line rupture outside primary containment.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission’s regulations for FP, ATWS, SBO, and the EQ program.

<u>USAR References</u>

Sections 3.6, 4.3.1.1, 4.4, and 7.4

<u>Components Subject to AMR</u>

Table 2.3.1-3 lists the RCPB and Connected Piping System component types that require AMR and their associated component intended functions.

Table 3.1.2-3 provides the results of the AMR.

Table 2.3.1-3
Reactor Coolant Pressure Boundary and Connected Piping System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (Steam SRV)	Pressure Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
CRD Return Line Welded Connection	Pressure Boundary
Heat Exchanger (Recirculating Pump Seal Cooler) Tube	Pressure Boundary
Orifice	Pressure Boundary Throttle
Piping, Piping Components	Leakage Boundary Pressure Boundary Structural Integrity (Attached)
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary
Pump Casing (Recirculation)	Pressure Boundary
Reactor Coolant Pressure Boundary Components Subject to Fatigue	Pressure Boundary
Tanks (T-208A/B)	Leakage Boundary
Valve Body	Leakage Boundary Pressure Boundary
Valve Body (Class 1)	Pressure Boundary

2.3.2 Engineered Safety Features

2.3.2.1 Core Spray

Description

The CSP System restores and maintains the coolant in the reactor pressure vessel in combination with other Emergency Core Cooling Systems (ECCSs) such that the core is adequately cooled to preclude fuel damage. Two independent CSP System loops are provided for use under LOCA conditions associated with large pipe breaks and reactor vessel depressurization. Suction water is normally supplied from the suppression pool but can also be supplied by the CST tanks.

The in-scope portion of the CSP System consists of the two main loops, including the pumps, piping, piping components, and valves. The components for the CSP System are located in the Reactor Building, with additional piping and valves located in the Primary Containment. The major in-scope components for the CSP System include two CSP pumps and the associated valves, piping, and instrumentation.

The CSP System also provides for primary containment isolation, but Class 1 boundary components that carry a CSP equipment designation are addressed in the RCPB and Connected Piping System (Section 2.3.1.3) along with any other CSP components downstream of primary containment isolation valves.

Boundary

The SLR boundaries for the CSP System are reflected on the SLRBDs listed below. There was one change with the addition of valves CS-27-1 and CS-28-1 on SLR-36248. The only significant differences between these boundaries and the original boundary drawings are on SLR-36248 and the boundary between the CSP and the RCPB and Connected Piping System (Section 2.3.1.3) has been moved to just outside the isolation valves, all CSP components downstream of these valves are now part of the RCPB and Connected Piping System. This change in CSP boundary means that P&ID NH-36242 sheet 1 no longer has any portion covered by this CSP AMR. The interfaces between the CSP System and other systems can be seen on the SLRBDs.

SLR-36248
SLR-36664

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Restore and maintain coolant in the reactor vessel, in combination with other ECCS, such that the core is adequately cooled to prevent fuel damage.

(2) Reflood the vessel and maintain inventory, in order to proceed to cold shutdown, as part of the ASCM.

(3) Portions of the CSP System relay logic control operation of other ECCS and supporting systems.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP, SBO, and the EQ program.

USAR References

Section 6.2.2

Components Subject to AMR

Table 2.3.2-1 lists the CSP System component types that require AMR and their associated component intended functions.

Table 3.2.2-1 provides the results of the AMR.

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

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Core Spray Pump Motor Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger (Core Spray Pump Motor Oil Cooler) Tubes	Pressure Boundary
Orifice	Pressure Boundary Throttle
Piping, Piping Components	Pressure Boundary Leakage Boundary
Pump Casing (Core Spray)	Pressure Boundary
Valve Body	Pressure Boundary Leakage Boundary

2.3.2.2 High Pressure Coolant Injection

Description

The HPCI System is part of the ECCS. The ECCS provides for continuity of reactor core cooling over the entire range of postulated breaks in the RCPB. The HPCI System provides adequate core cooling for all break sizes less than those sizes for which the LPCI subsystem or CSP System can adequately protect the core, without assistance from other safeguards systems. The HPCI System performs this function without reliance on off-site power or a water source for the injection. The HPCI System can pump water into the RPV under LOCA conditions that do not result in rapid depressurization of the RPV.

The in-scope portion of the HPCI System consists of the main cooling loop, including the pumps, heat exchangers, accumulator, piping, and valves. The major in-scope components include: the main pump, booster pump, and drive turbine; gland seal condenser, blower, and condensate pump; manual and power operated valves and actuators, water-side, and steam-side piping, lubricating oil (LO) cooler, and the associated piping, valves, and instrumentation.

The HPCI System also provides for PCT isolation, but Class 1 boundary components that carry a HPCI equipment designation are addressed in the RCPB and Connected Piping System (Section 2.3.1.3) along with any other HPCI components inside the Class 1 boundary.

<u>Boundary</u>

The SLR boundaries for the HPCI System are reflected on the SLRBDs listed below. The interfaces between the HPCI System and other systems are identified on the SLRBDs. The only significant difference between these boundaries and the initial LR system boundaries is shown on SLR-36249. The boundary between the HPCI and the RCPB and Connected Piping System (Section 2.3.1.3) has been moved to just outboard of containment isolation valves. All HPCI components inboard of these valves are now part of the RCPB and Connected Piping System.

SLR-36241
SLR-36249
SLR-36249-1
SLR-36250
SLR-36254

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

(1) Restore and maintain reactor coolant level following postulated design basis events.

(2) Operate in the “Reactor Vessel Level Control” or “Reactor Vessel Pressure Control” mode as required.

(3) HPCI Steam Supply Line Isolation. Detects HPCI steam supply line breaks and provides a signal to automatically close supply line isolation valves on high steam flow or area temperature.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for SBO and the EQ program.

USAR References

Section 6.2.4

Components Subject to AMR

Table 2.3.2-2 lists the HPCI System component types that require AMR and their associated component intended functions

Table 3.2.2-2 provides the results of the AMR.

Table 2.3.2-2
High Pressure Coolant Injection System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Blower Housing (HPCI Turbine Gland Seal Condenser)	Leakage Boundary
Bolting (Closure)	Mechanical Closure
Heat Exchanger (HPCI Gland Seal Condenser) Shell Side Components	Leakage Boundary
Heat Exchanger (HPCI Gland Seal Condenser) Tubes	Pressure Boundary
Heat Exchanger (HPCI Gland Seal Condenser) Tube Sheet	Pressure Boundary
Heat Exchanger (HPCI Gland Seal Condenser) Tube Side Components	Pressure Boundary
Heat Exchanger (HPCI Lubricating Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger (HPCI Lubricating Oil Cooler) Tubes	Pressure Boundary Heat Transfer
Heat Exchanger (HPCI Lubricating Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger (HPCI Lubricating Oil Cooler) Tube Side Components	Pressure Boundary
Insulation - Thermal	Thermal Insulation
Orifice	Pressure Boundary Throttle
Piping Elements	Pressure Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (HPCI Booster)	Pressure Boundary
Pump Casing (HPCI Turbine Aux Oil)	Pressure Boundary
Pump Casing (HPCI Turbine Driven Lubricating Oil)	Pressure Boundary
Pump Casing (HPCI Turbine Gland Seal CDSR Drain)	Leakage Boundary

Table 2.3.2-2
High Pressure Coolant Injection System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Pump Casing (HPCI)	Pressure Boundary
Strainer (Element)	Filter
Tank (CV-2065 Accumulator)	Pressure Boundary
Tank (HPCI Turbine Lubricating Oil)	Pressure Boundary
Turbine Casings (HPCI Drive)	Pressure Boundary
Valve Body	Pressure Boundary Leakage Boundary

2.3.2.3 Primary Containment Mechanical

Description

The PCM System was created for LR evaluation purposes. Specifically, the PCM System separated out the mechanical components of the PCT System, but it also consolidated portions of numerous plant systems, subsystems, and components that were more convenient to evaluate within the PCM System. The PCM System includes portions of the following plant systems, subsystems, and components:

- Mechanical portions of the Primary Containment (PCT) System
- Combustible Gas Control (CGC)
- Containment Atmosphere Control and Nitrogen Control components
- Hydrogen-Oxygen Analyzing (HOA) System
- Post LOCA Accident Sampling (PAS) System
- Hard Pipe Vent (HPV) subsystem
- Containment isolation valves of the Traversing In-core Probe (TIP) System

These plant systems, subsystems, and components are combined into the PCM System for SLR purposes. A description of each of these systems is provided below:

Primary Containment System:

The Primary Containment System consist of a drywell and a wetwell. The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion. The suppression chamber (i.e. wetwell) is in the shape of a torus which is below and encircles the drywell. The drywell is connected to the wetwell by eight vent lines, which combine into a common header within the suppression chamber. Downcomers from the header terminate below the water level of the suppression pool.

In the event of a LOCA inside the drywell, reactor water and steam would be released into the drywell atmosphere. The resulting rise in drywell pressure forces the mixture of air, N_2, steam, and water through the vents into the suppression pool water in the wetwell (torus). The steam is condensed rapidly and completely in the wetwell pool, resulting in a rapid pressure reduction in the drywell. Vacuum relief valves (RVs)between the wetwell and drywell relieve the pressure of non-condensable gases forced into the wetwell with the steam and water mixture and prevent wetwell pressurization and the accompanying back flow of water from the wetwell to the drywell.

The PCM System includes the portions of the mechanical containment penetration assemblies that are considered extensions of the mechanical piping; these are the flued heads and guard pipes of the mechanical containment penetration assemblies. The other components of the containment penetration assemblies (e.g., the sleeves) are evaluated in the PCT System.

<u>Combustible Gas Control</u>

The Combustible Gas Control System was designed to control primary containment oxygen concentrations following a loss of coolant accident. License Amendment 138 to Monticello Facility Operating License DPR-22 eliminated the requirement for the system. The system has been abandoned by cutting and capping the process lines interfacing with the PCM System and the RHR System. The portion of the cut and capped CGC piping that was in scope for initial LR interfacing with the PCM System has been included with the PCM System.

<u>Containment Atmosphere Control and Nitrogen Control System:</u>

The Primary Containment Atmospheric Control and Nitrogen Control System introduces a N_2 atmosphere into the primary containment. By reducing the oxygen content, hydrogen generated by a metal-water reaction with the fuel cladding during early phases of loss-of-coolant accidents cannot ignite and damage the containment structure. The system utilizes a liquid N_2 supply and a steam vaporizer for initial purging. The steam vaporizer unit converts the liquid N_2 into a gas which then flows through a pressure reducing valve and flow meter into the drywell and wetwell.

The drywell ventilation coolers are utilized during the purging operation to maximize the mixing of N_2 and oxygen. Primary containment pressure is maintained by either venting the gas to the Standby Gas Treatment System or the Reactor Building exhaust. The makeup supply utilizes a liquid N_2 supply and an atmospheric vaporizer. An air purge fan with ducting to the N_2 purge line is incorporated as part of the Atmospheric Control System. This arrangement permits restoration of a breathable atmosphere within the drywell and suppression chamber prior to maintenance operations. Debris screens are installed on the drywell and wetwell purge and vent penetrations. The function of the primary containment debris screens is to prevent the entry of foreign material into the purge and vent lines during a postulated DBA.

Hydrogen-Oxygen Analyzing System:

The Hydrogen-Oxygen Analyzing System consists of two redundant and independent monitoring divisions with each division having an analyzer panel, associated valves and piping, separate sample points, and associated electrical control and indication powered from one of the emergency divisions. The Hydrogen-Oxygen Analyzing System was originally installed as a Safety Grade System intended for use after an accident to monitor the hydrogen and oxygen concentration in the drywell and suppression chamber, and it shares a common sample point for the Post-Accident Sample System. The revised 10 CFR 50.44 no longer defines a design-basis LOCA hydrogen release and eliminates requirements for hydrogen control systems to mitigate such a release. The hydrogen monitors are required to assess the degree of core damage during a beyond design-basis accident.

Post LOCA Accident Sampling System:

The Post LOCA Accident Sampling System can obtain highly radioactive liquid and gas samples for radiological analysis. The liquid samples are representative of liquids within the reactor coolant and RHR System. The gas samples are representative of the atmosphere within the torus and Primary Containment.

Hard Pipe Vent Subsystem:

The Hard Pipe Vent Subsystem provides a vent path from the pressure suppression chamber (wetwell) vapor space to a release point above the Reactor Building. The vent path comprises an 8-in, penetration in the top of the suppression chamber, two pneumatically operated primary containment isolation valves, a rupture disc, a radiation monitor, and piping routed from the primary containment penetration through secondary containment and up the outside of the Reactor Building to a point above the roof.

TIP (Traversing In-core Probe) System:

The Traversing In-core Probe System containment isolation valves are included in the PCM System.

Boundary

The PCT System is shown on the SLRBDs listed below.

SLR-36049-14
SLR-36246
SLR-36247
SLR-36258
SLR-36267
SLR-46162
SLR-91197
SLR-96042-1
SLR-116629
SLR-161004

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide vacuum relief between the torus and drywell, and between the torus and Reactor Building, to limit the negative pressure in either the torus or drywell to less than the design pressure of negative 2 psid.

(2) Provides primary containment isolation for those portions of the system that interface with the primary containment (valves and piping). Included are the containment Atmosphere Control and Nitrogen Control System lines, the Hydrogen-Oxygen Analyzing (HOA) System lines, the Post Accident Sampling (PAS) System lines and the Hard Pipe Vent (HPV) System lines. Also included in PCM System are the TIP System ball and shear valves.

(3) Provide secondary containment integrity for the Hard Pipe Vent. A portion of the Hard Pipe Vent piping downstream of the rupture disc is SR and in scope of LR because a breach of the vent piping pressure boundary could cause a breach of secondary containment.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP, EQ, and SBO.

USAR References

Sections 5.2.2.1, 5.2.2.2, 5.2.2.3, 5.2.2.5.3, 5.2.2.6, 5.2.2.7, 5.2.2.9, 7.3.5.4, 10.3.10

Components Subject to AMR

Table 2.3.2-3 lists the PCM System component types that require AMR and their associated component intended functions.

Table 3.2.2-3 provides the results of the AMR.

Table 2.3.2-3
Primary Containment Mechanical System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (Instrument Air)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Primary Containment Purge Vaporizer) Shell Side Components	Leakage Boundary

Table 2.3.2-3
Primary Containment Mechanical System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heat Exchanger (Primary Containment Purge Vaporizer) Tube Side Components	Leakage Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary Structural Integrity (Attached)
Rupture Disks	Pressure Boundary
Strainer (Element)	Filter
Valve Body	Leakage Boundary Pressure Boundary Structural Integrity (Attached)

2.3.2.4 Reactor Core Isolation Cooling

Description

The RCIC System utilizes a steam-driven turbine to drive a pump to inject water into the reactor vessel such that the core is not uncovered in the event of a loss of off-site alternate current (AC) power or a loss of feedwater. The RCIC pump supplies demineralized makeup water from the CST tank and can utilize the suppression pool as an alternate SR source of water.

The RCIC System pump delivers water into the reactor vessel through a feedwater line where it is distributed through the Reactor Feedwater System spargers. The pumping capacity of the RCIC System is sufficient to maintain the water level above the core without any other makeup water system in operation. The turbine is driven with steam from the reactor vessel and exhausts the steam to the suppression pool through a condensing sparger submerged in the torus water.

The in-scope portion of the RCIC System consists of the steam turbine supply and exhaust line, steam turbine, steam drain lines, the pump, suction and discharge piping, valves, and a barometric steam condenser.

The RCIC System also provides for PCT isolation, but Class 1 boundary components that carry a RCIC equipment designation are addressed in the RCPB and Connected Piping System (Section 2.3.1.3) along with any other RCIC components inside the Class 1 boundary.

Boundary

The SLR boundaries for the RCIC System are reflected on the SLRBDs listed below. The interfaces between the RCIC System and other systems are identified on the SLRBDs. The only significant difference between these boundaries and the initial LR system boundaries is shown on SLR-36251. The boundary between the RCIC and the RCPB and Connected Piping System (Section 2.3.1.3) has been moved to just outboard of containment isolation valves. All RCIC components inboard of these valves are now part of the RCPB and Connected Piping System.

SLR-36241
SLR-36251
SLR-36252
SLR-36254

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Maintain sufficient reactor coolant in the reactor vessel so that the core is not uncovered in the event of a loss of off-site AC power or a loss of feedwater event.

(2) RCIC steam supply line isolation. Detects RCIC steam supply line breaks and provides a signal to automatically close supply line isolation valves on high steam flow or area temperature.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the EQ program.

USAR References

Section 10.2.5

Components Subject to AMR

Table 2.3.2-4 lists the RCIC System component types that require AMR and their associated component intended functions.

Table 3.2.2-4 provides the results of the AMR.

Table 2.3.2-4
Reactor Core Isolation Cooling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (CV-2104 Minimum Flow Valve Accumulator)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Heat Exchanger (RCIC Barometric Condenser and Vacuum Tank) Shell Side Components	Pressure Boundary

Table 2.3.2-4
Reactor Core Isolation Cooling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heat Exchanger (RCIC Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger (RCIC Oil Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger (RCIC Oil Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger (RCIC Oil Cooler) Tubes	Heat Transfer Pressure Boundary
Orifice	Pressure Boundary Throttle
Piping Elements	Leakage Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (Lubricating Oil)	Pressure Boundary
Pump Casing (RCIC Barometric Condenser Vacuum Pump)	Leakage Boundary
Pump Casing (RCIC Pump)	Pressure Boundary
Pump Casing (RCIC Turbine Barometric Condenser Condensate Pump)	Pressure Boundary
Strainer (Element)	Filter
Turbine Casings (RCIC Terry Turbine)	Pressure Boundary
Valve Body	Leakage Boundary Pressure Boundary

2.3.2.5 Residual Heat Removal

Description

The RHR System restores and maintains the reactor coolant inventory in the reactor core such that the reactor core is adequately cooled after depressurization during a loss-of-coolant accident (LOCA). The RHR System also provides cooling for the suppression pool such that condensation of the steam resulting from the blowdown due to the design basis LOCA is ensured. The RHR System further extends the redundancy of the ECCS by providing for primary containment spray/cooling. The RHR System is designed for essentially three modes of operation:

(1) LPCI

(2) Containment spray/cooling

(3) Reactor shutdown cooling

The in-scope portion of the RHR System consists of the main cooling loops, including the pumps, heat exchangers cooled by the ESW System, piping, and valves. The major in-scope components include: two heat exchangers, four RHR pumps, and the associated valves, piping, and instrumentation.

The RHR System also provides for PCT isolation, but Class 1 boundary components that carry a RHR equipment designation are addressed in the RCPB and Connected Piping System (Section 2.3.1.3) along with any other RHR components inboard of the containment isolation valves.

Boundary

The SLR boundaries for the RHR System are reflected on the SLRBDs listed below. The interfaces between the RHR System and other systems are identified on the SLRBDs. The only significant difference between these boundaries and the initial LR system boundaries is shown on SLR-36246 and SLR-36247. The boundary between the RHR and the RCPB and Connected Piping System (Section 2.3.1.3) has been moved to just outboard of containment isolation valves. All RHR components inboard of these valves are now part of the RCPB and Connected Piping System.

SLR-36042-2
SLR-36049-13
SLR-36243
SLR-36246
SLR-36247
SLR-36248
SLR-36256
SLR-36664
SLR-96042-1

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(4) Automatically inject water into the reactor vessel in LPCI cooling mode after depressurization following a LOCA.

(5) Provide containment spray/cooling to drywell and torus as an augmented means of removing heat after a LOCA (containment spray/cooling mode) and maintain suppression pool temperature below that required to condense steam after a LOCA.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the FP, SBO, ATWS and EQ program.

USAR References

Section 6.2.3

Components Subject to AMR

Table 2.3.2-5 lists the RHR System component types that require AMR and their associated component intended functions.

Table 3.2.2-5 provides the results of the AMR.

Table 2.3.2-5
Residual Heat Removal System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (Minimum Flow Valve Accumulators)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Heat Exchanger (RHR Heat Exchanger) Shell Side Components	Pressure Boundary
Heat Exchanger (RHR Heat Exchanger) Tube Sheet	Pressure Boundary
Heat Exchanger (RHR Heat Exchanger) Tube Side Components	Pressure Boundary
Heat Exchanger (RHR Heat Exchanger) Tubes	Heat Transfer Pressure Boundary
Heat Exchanger (RHR Pump Oil Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger (RHR Pump Oil Cooler) Tubes	Heat Transfer Pressure Boundary
Heat Exchanger (RHR Pump Seal Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger (RHR Pump Seal Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger (RHR Pump Seal Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger (RHR Pump Seal Cooler) Tubes	Pressure Boundary
Insulation – Thermal	Thermal Insulation
Orifice	Pressure Boundary Throttle
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (RHR Pump)	Pressure Boundary
Spray Nozzles	Spray
Strainer (Element)	Filter
Valve Body	Leakage Boundary Pressure Boundary

2.3.2.6 Secondary Containment

Description

The SCT System completely encloses the reactor and its pressure suppression primary containment. The SCT enclosure structure provides secondary containment when the PCT is closed and in service, and primary containment when the PCT is open, as during refueling.

The SGTS is a subsystem of the SCT System and is provided to maintain, whenever SCT isolation conditions exist, a small negative pressure to minimize ground level escape of airborne radioactivity. Filters are provided in the system to remove radioactive particulates, and charcoal adsorbers are provided to remove radioactive halogens. All flow from the Standby Gas Treatment System is released through the elevated off-gas vent stack and continuously monitored by the Stack Gas Monitoring System.

The primary purposes for the SCT are to minimize ground level release of airborne radioactive materials to the environs, and to provide means for a controlled elevated release of the building atmosphere if an accident should occur. The SGTS provides ventilation for 180 days post LOCA to support removal of heat loads in the reactor building. The post LOCA reactor building environmental profile is used in EQ analysis for qualification of equipment during the EQ coping period.

For the design basis fuel-handling accident, analysis using AST methodology has demonstrated that secondary containment integrity and operation of the SGTS are not required to maintain offsite and Control Room operator doses below 10 CFR 50.67 limits. SCT and SGTS are not required for the design basis main steam line break and control rod drop accidents since releases from those accidents are outside the secondary containment.

The in-scope portion of the SCT System consists of isolation dampers on the Reactor Building HVAC supply and the primary containment vent air discharge lines to the Main Exhaust Plenum Room, isolation dampers in the Reactor Building air supply units, isolation dampers in the SCT to SGTS room HVAC ducting, the air intake line from the PCT purge and vent, and lines leading up to the discharge of the off-gas dilution fans.

<u>Boundary</u>

The SCT System boundaries are shown on the following SLRBDs:

SLR-36159
SLR-36258
SLR-36266
SLR-36267
SLR-36267-3
SLR-36807
SLR-36808
SLR-36881
SLR-46162
SLR-51142-1
SLR-67588
SLR-9288-14

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Minimize ground level release of airborne radioactive materials to the environs and provides means for a controlled elevated release of the building atmosphere in the event of a design basis LOCA.

(2) Establish a sub atmospheric pressure in the SCT and provides a filtered SCT exhaust flow path to an elevated release point in the event of an accident, which requires that SCT integrity be established.

(3) Provide ventilation for 180 days post LOCA to support removal of heat loads in the reactor building. The post LOCA reactor building environmental profile is used in EQ analysis for qualification of equipment during the EQ coping period.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

None.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the EQ program.

USAR References

Section 5.3

Components Subject to AMR

Table 2.3.2-6 lists the SCT System component types that require AMR and their associated component intended functions.

Table 3.2.2-6 provides the results of the AMR.

Table 2.3.2-6
Secondary Containment System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Blower Housing (Fan)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Bolting (HVAC Closure)	Mechanical Closure
Ducting and Components	Filter Pressure Boundary
Orifice	Pressure Boundary Throttle
Piping, Piping Components	Pressure Boundary
Valve Body	Pressure Boundary

2.3.3 Auxiliary Systems

2.3.3.1 Alternate Nitrogen

Description

The AN2 System provides the pneumatic supply for various components (e.g., the hard pipe vent system isolation valves, six of the eight safety relief valves, the inboard main steam isolation valves) during accident scenarios when the NSR pneumatic supplies (instrument air and instrument nitrogen) may be unavailable. The AN2 System consists of two separate SR trains providing a SR backup pneumatic source from N_2 bottle racks. The location of the bottle racks permits replacement of N_2 bottles to maintain the N_2 pressure during normal operation and following an accident. The AN2 System interfaces with the Instrument and Service Air (AIR) System through check valves with the N_2 side held at a slightly lower pressure to allow the AIR System to be utilized during normal operation. In the event of an accident, which also disables the AIR System, the AN2 System would automatically supply the required pneumatic loads.

Train A provides backup pneumatic supply to the T-ring seals of the Inboard Primary Containment Atmospheric Control System purge and vent valves, the T-ring seals, and actuators of the Reactor Building to suppression chamber vacuum breakers, and safety relief valves RV-2-71A, RV-2-71B and RV-2-71E. Train B provides backup pneumatic supply to the T-ring seals of the outboard Primary Containment Atmospheric Control System purge and vent valves, inboard main steam isolation valves, and safety relief valves RV-2-71C, RV-2-71F, and RV-2-71H. Manifold and system pressures of each train are monitored by pressure switches which give control room annunciation on low pressure.

The AN2 System is entirely in-scope of SLR. The boundary for the supply to the APR System, moved to the scope of the RCPB and Connected Piping System for SLR, extends up to the solenoid valve controlling the safety relief valves. The boundary for the supply to the main steam isolation valves (MSIVs) extends up to the AN2 side of the MST System check valves upstream of the MSIV pneumatic control consoles. These MST check valves have also moved to the RCPB scope for SLR. The in-scope portion of the AN2 lines to the T-Ring seals extends to the check valve upstream of the accumulators serving each seal. The accumulators and seals are scoped as components in the PCM System. These AN2 System components subject to an AMR extend from the mentioned pneumatically served components in the drywell and at the primary containment boundary back to the N_2 supply bottles in the Turbine Building.

Boundary

The AN2 System boundaries are shown on the following SLRBDs:

SLR-36049-10
SLR-36049-14
SLR-36241-1

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides the pneumatic supply to six SRVs during accident scenarios when the NSR pneumatic supplies may be unavailable.

(2) Provides the pneumatic supply to the inboard MSIVs as a source of sealing force margin. The sealing force provided by the MSIV actuator springs needs additional force provided by the nitrogen to tightly seal the MSIVs due to minor wear, degradation, and minor misalignments.

(3) Provides the pneumatic supply to containment vent and purge valves, and Reactor Building to suppression pool vacuum breaker valves.

(4) Provides primary containment isolation for those portions of the system that interface with the primary containment (valves and piping).

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR attached components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP, EQ, and SBO.

USAR References

Sections 4.4.2.1, 5.2.2.5.3.1, 5.2.2.5.4, 8.12, and 10.3.4
Appendix J

Components Subject to AMR

Table 2.3.3-1 lists the AN2 System component types that require AMR and their associated component intended functions.

Table 3.3.2-1 provides the results of the AMR.

Table 2.3.3-1
Alternate Nitrogen System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (MSIV Accumulators)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Hoses	Pressure Boundary
Piping, Piping Components	Pressure Boundary Structural Integrity (Attached)
Valve Body	Pressure Boundary Structural Integrity (Attached)

2.3.3.2 Chemistry Sampling

Description

The Chemistry Sampling System provides for sampling the process fluid of various systems to obtain representative data from which the performance of the plant systems and equipment can be evaluated. The sampling locations are chosen to ensure that representative samples can be obtained. The sample streams are routed by the shortest route to a common sample collection area.

There is a collective sample station for each building in the plant: Radwaste Building sample station, located in the Radwaste Building; Reactor Building sample station, located in the Reactor Building; and Turbine Building sample station, located in the Turbine Building. The stations are provided with closed loop process lines that discharge to the equipment drain tanks and then to the waste collector tank for reprocessing.

The in-scope portion of the CHM System consists of the piping and valves from the sample points for the various interfacing systems to the Reactor Building sample station and Turbine Building sample station, as applicable. The major in-scope components include piping, valves and instrumentation located at the Reactor Building sample station and Turbine Building sample station, and portions of the system for cooling the process samples (sample coolers and sample chillers).

Boundary

The CHM System boundaries are shown on the following SLRBDs:

SLR-36037
SLR-36038
SLR-36038-1
SLR-36038-2
SLR-36042
SLR-36243
SLR-36254
SLR-36257
SLR-36829
SLR-36908

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with safety-related components could prevent satisfactory accomplishment of a safety function. It includes NSR SSCs that have the potential for spatial interactions (spray or leakage) with SR SSCs.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Section 10.3.7

Components Subject to AMR

Table 2.3.3-2 lists the CHM System component types that require AMR and their associated component intended functions.

Table 3.3.2-2 provides the results of the AMR.

Table 2.3.3-2
Chemistry Sampling System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (Sampler Chillers/Coolers) Shell Side Components	Leakage Boundary
Piping, Piping Components	Leakage Boundary
Valve Body	Leakage Boundary

2.3.3.3 Circulating Water

Description

The CWT System removes the heat from the main condenser that is rejected by the Turbine or Turbine Bypass System over the full range of operating loads.

The CWT System is a flexible multi-cycle system with the capability of once-through circulation of river water, recirculation in a closed cycle with Cooling Towers, and several variations of these basic modes. Selection of the operating mode will be determined by the prevailing river flow rate and river temperature to provide economic plant operation and conformance with restrictions on river water use.

The system is equipped with two half-capacity CWT pumps located at the INS. The pumps are designed to circulate cooling water through the main condenser. Effluent from the condenser, and the plant's Service Water (SW) System, is piped to the discharge structure. During open cycle operation, the CWT flows through the discharge structure to an open canal, which conveys it to the river downstream of the intake.

Two half-capacity cooling tower pumps, located at the discharge structure, are used during cooling tower operation. The pumps are designed to operate in series with the CWT pumps, discharging flow to each of two induced draft cooling towers. During closed cycle, when the river is isolated by control gates, effluent from the cooling towers flows by gravity from the cooling tower basins to the suction chambers of the CWT pumps. Blowdown overflows through weirs at the cooling tower basins and is piped from there to the discharge canal. Make-up water and microbiological growth inhibitor are added at the INS.

The in-scope portion of the CWT consists of the main cooling loops, including the CWT pumps, piping, and valves from the pumps to the main condenser, piping, and valves from the main condenser to the exit point from the turbine building, as well as pumps, piping and valves associated with water box scavenging. In addition is a portion of piping and valves associated with sodium hypochlorite injection.

<u>Boundary</u>

The CWT boundaries are shown on the following SLRBDs:

SLR-36489
SLR-36666
SLR-36667

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

<u>USAR References</u>

Section 11.5

Components Subject to AMR

Table 2.3.3-3 lists the CWT System component types that require AMR and their associated component intended functions.

Table 3.3.2-3 provides the results of the AMR.

Table 2.3.3-3
Circulating Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Expansion Joints	Leakage Boundary
Heat Exchanger (Condenser Water Box) Tube Side Components	Leakage Boundary
Piping Elements	Leakage Boundary
Piping, Piping Components	Leakage Boundary
Pump Casing (Circulating Water)	Leakage Boundary
Pump Casing (Circulating Water Sump Pump)	Leakage Boundary
Pump Casing (Water Box Pump-Down)	Leakage Boundary
Pump Casing (Water Box Scavenging)	Leakage Boundary
Tanks (Vacuum Control)	Leakage Boundary
Tanks (Water Separator)	Leakage Boundary
Valve Body	Leakage Boundary

2.3.3.4 Control Rod Drive

Description

The CRD System is designed to allow control rod withdrawal or insertion at a limited rate, one control rod at a time, for power level control and flux shaping during reactor operation. Stored energy available from gas-charged accumulators and/or from reactor pressure provides hydraulic power for rapid simultaneous insertion of all control rods for rapid (scram) reactor shutdown. Each control rod has its own separate drive mechanism, control, and scram devices.

The CRD System is designed so that sufficient energy is available to force the control rods into the core under conditions associated with abnormal operational transients and accidents. Control rod insertion speed is sufficient to prevent fuel damage as a result of any abnormal operational transient.

The CRD System also supplies water to the RVI reference leg backfill subsystem. This subsystem provides a constant backfill of water from the CRD System's charging water header to the safeguards and feedwater reference legs to flush any gas-laden water through the condensate chambers and back to the reactor vessel to eliminate level errors due to the degassing phenomenon.

The hydraulic control unit, the control rod drive mechanisms, piping, and the scram valves retain reactor coolant following a scram. Portions of the reference leg backfill subsystem are also reactor coolant pressure boundaries.

Portions of the CRD System are required to support primary containment isolation. Containment isolation of the CRD hydraulic control lines is provided by double seals within each control rod drive mechanism, and check valves and normally closed valves within each hydraulic control unit.

Boundary

The in-scope portion of the CRD System includes the pumps, heat exchangers, tanks, and associated piping, valves, and instrumentation from the CRD pumps suction to and including the CRD hydraulic control units as well as the RVI reference leg back fill subsystem.

The interfaces between the CRD System and other systems can be seen on the SLRBDs listed below.

SLR-36036
SLR-36039
SLR-36042
SLR-36043
SLR-36044
SLR-36242-1
SLR-36242-2
SLR-36244
SLR-36245
SLR-36254

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The CRD System is required to rapidly insert withdrawn neutron absorbing control rods into the core (scram) in response to automatic signals from the RPS providing reactivity control. The CRD System was designed to perform a reliable all rods reactor scram by forcing high pressure water, from 121 rod specific accumulators or the reactor, underneath the rod's hydraulic drive pistons. Rod shaft latching mechanisms maintain the rods fully inserted for the duration of the shutdown.

(2) Portions of the CRD System are connected to, and part of, the RCPB during plant operation. The hydraulic control unit, the rod drive mechanisms, piping, and the scram valves retain reactor coolant following a scram. Portions of the reference leg backfill system are also reactor coolant pressure boundaries.

(3) The CRD System provides primary containment isolation for those portions of the system that interface with the primary containment (valves and piping). Portions of the system are required to support primary containment isolation.

Containment isolation of the CRD hydraulic control lines is provided by double seals within each control rod drive mechanism, and check valves and normally closed valves within each hydraulic control unit.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP, ATWS, SBO, and the EQ program.

USAR References

Section 3.5.3

Components Subject to AMR

Table 2.3.3-4 lists the CRD System component types that require AMR and their associated component intended functions.

Table 3.3.2-4 provides the results of the AMR.

Table 2.3.3-4
Control Rod Drive System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (Scram)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Heat Exchanger (CRD PMP Thrust BRG CLR) Shell	Pressure Boundary
Heat Exchanger (CRD PMP Thrust BRG CLR) Tubes	Heat Transfer Pressure Boundary
Orifice	Pressure Boundary Throttle
Piping, Piping Components	Pressure Boundary Structural Integrity (Attached)
Pump Casing (CRD)	Pressure Boundary
Pump Casing (Lubricating Oil)	Pressure Boundary
Speed Increaser Assembly	Pressure Boundary
Tanks (Scram Discharge)	Pressure Boundary
Valve Body	Pressure Boundary

2.3.3.5 Demineralized Water

Description

The DWS provides for storage and distribution of high quality, non-radioactive demineralized water for use as makeup to the CST System and other systems requiring high quality demineralized water. The DWS is NSR and is not required during or following DBEs. The DWS includes the Makeup Demineralizer (MUD) subsystem. The MUD subsystem is a double-pass Reverse Osmosis (RO) System used to purify and demineralize well water. This demineralized water is used for various plant services where quality water is required to (1) minimize damage to components due to chemical and corrosive attack; (2) minimize the fouling of heat transfer surfaces and mechanical parts; and (3) minimize impurities available for activation in neutron flux zones. The MUD subsystem is also NSR and is not required during or following DBEs. The DWS includes piping that penetrates the primary containment which includes manual containment isolation valves which provide for primary containment isolation when containment integrity is required.

Demineralized water is distributed to two primary headers, the Turbine and Reactor Building service header, and the CST System makeup headers. The service header to the Turbine Building supplies water to the stator cooling, heating boiler, makeup demineralizer process water, sample station, and several hose stations located throughout the Turbine Building. The header to the Reactor Building supplies the Standby Liquid Control System, RBC System surge tank, off-gas stack, laboratory, sample station, and various hose stations throughout the Reactor Building. The hose stations are used during general plant cleaning and decontamination procedures. Hose connections in the drywell are used to support refueling activities. The DWS is normally operated continuously during normal plant operation to maintain water quality.

The in-scope portion of the DWS consists of MUD filters, softeners, reverse osmosis units, heater, deionizing units, a reverse osmosis cleaning subsystem, a heat exchanger, two transfer pumps, and the associated piping and instrumentation. The DWS System also includes primary containment isolation valves.

Boundary

The DWS System boundaries are shown on the following SLRBDs:

SLR-36036
SLR-36039
SLR-36040
SLR-36041-2
SLR-36042
SLR-36046
SLR-36050
SLR-36052
SLR-36159
SLR-36253
SLR-36255
SLR-36261

SLR-36348
SLR-36664
SLR-36881
SLR-96042-1

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The DWS System includes manually operated primary containment isolation valves.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Section 10.3.3
Table 5.2-3a

Components Subject to AMR

Table 2.3.3-5 lists the DWS System component types that require AMR and their associated component intended functions.

Table 3.3.2-5 provides the results of the AMR.

Table 2.3.3-5
Demineralized Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Demin Water Tank Heat Exchanger) Shell Side Components	Leakage Boundary
Heat Exchanger (Demin Water Tank Heat Exchanger) Tube Side Components	Leakage Boundary
Piping, Piping Components	Pressure Boundary Leakage Boundary
Pump Casing (Demin Water Transfer Pump, RO 1st & 2nd Pass Pumps, Chemical Add Pump)	Leakage Boundary
Pump Casing (RO Cleaning Concentrate Pump)	Leakage Boundary
Tanks (Caustic Storage Tank)	Leakage Boundary

Table 2.3.3-5
Demineralized Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Tanks (Depth Filter, Softener Tanks, Brine Tank)	Leakage Boundary
Tanks (RO Cleaning Solution Tank, Mixed Bed Deionizer Tanks, Standby Tank)	Leakage Boundary
UV Light Housing	Leakage Boundary
Valve Body	Pressure Boundary Leakage Boundary

2.3.3.6 Emergency Diesel Generators

Description

The DGN System includes the Diesel Oil (DOL) System as a subsystem for SLR purposes.

The DGN System consists of two independent diesel generator (DG) units. Each DG unit can supply one train of essential power to the plant. Each train of essential power supplies enough components to allow safe shutdown and cool down of the plant, thus accomplishing the system function. Each diesel engine, generator, engine control panel, and auxiliaries are mounted on a common base. Each unit and its associated electrical control panel are enclosed in a seismically-designed Class 1 structure for protection against tornadic winds or missiles. Each DG has a local fuel tank, located under the auxiliary section of the local skid, called the base tank that supplies the fuel to the engine. Each unit has two electric fuel oil transfer pumps, powered by transformers from the generator output, to fill the base tank from its local day tank. Each DG has a separate dedicated day tank enclosed in a separate cell in the DG building. The day tank/base tank local fuel supply combination has capacity for eight hours of operation at full load of the unit. A backup fuel oil storage tank provides fuel for one week of full load operation of one unit. Each DG is designed to start and run independently of any external AC electrical power. There are two independent air starting systems for each diesel engine. Starting logic, controls, alarms, and auxiliary pump motors for each DG are supplied from the plant batteries. Other auxiliary equipment required to ensure continuous operation of the engines is supplied from the essential busses (ESW pumps) or control power transformers associated with the engine driven generator (local fuel transfer pumps). Some auxiliaries needed only in the standby state of the DG (circulating oil pump, turbo circulating oil pump) are supplied from non-essential power supplies.

The DOL Subsystem in SLR scope comprises four positive displacement pumps, four tanks and associated distribution piping and instrumentation.

Boundary

The DGN System boundaries are shown on the following SLRBDs:

SLR-36051

SLR-36051-1
SLR-36664

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide 4.16 kV power to essential buses #15 and #16, when normal sources (2R and 1R) are not available. This function is credited in accident analyses.

(2) The Diesel Oil subsystem provides for the storage and distribution of fuel oil used in the operation of the EDGs.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) The system contains structures and/or components which perform functions credited in the current licensing basis for FP. The DGN System provides onsite power and diesel oil to equipment relied on to achieve post-fire safe shutdown.

USAR References

Section 8.4

Components Subject to AMR

Table 2.3.3-6 lists the DGN System component types that require AMR and their associated component intended functions.

Table 3.3.2-6 provides the results of the AMR.

Table 2.3.3-6
Emergency Diesel Generators System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Electric Heaters (DG Jacket Coolant Heater Housing)	Pressure Boundary
Expansion Joints	Pressure Boundary
Flame Arrestor	Pressure Boundary
Flexible Connection	Pressure Boundary
Heat Exchanger (After Cooler) Fins	Heat Transfer
Heat Exchanger (After Cooler) Shell Side Components	Pressure Boundary
Heat Exchanger (After Cooler) Tube Sheet	Pressure Boundary
Heat Exchanger (After Cooler) Tube Side Components	Pressure Boundary
Heat Exchanger (After Cooler) Tubes	Heat Transfer Pressure Boundary
Heat Exchanger (Jacket Water) Shell Side Components	Pressure Boundary
Heat Exchanger (Jacket Water) Tube Sheet	Pressure Boundary
Heat Exchanger (Jacket Water) Tube Side Components	Pressure Boundary
Heat Exchanger (Jacket Water) Tubes	Heat Transfer Pressure Boundary
Heat Exchanger (Lubricating Oil) Fins	Heat Transfer
Heat Exchanger (Lubricating Oil) Shell Side Components	Pressure Boundary
Heat Exchanger (Lubricating Oil) Tube Sheet	Pressure Boundary
Heat Exchanger (Lubricating Oil) Tube Side Components	Pressure Boundary
Heat Exchanger (Lubricating Oil) Tubes	Heat Transfer Pressure Boundary
Piping Elements	Pressure Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary Structural Integrity (Attached)
Pump Casing (Fuel Oil)	Pressure Boundary
Pump Casing (Jacket Water)	Pressure Boundary
Pump Casing (Lubricating Oil)	Pressure Boundary
Silencer	Pressure Boundary
Strainer (Element)	Filter

Table 2.3.3-6
Emergency Diesel Generators System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Tanks (DG Fuel Oil Base Tank)	Pressure Boundary
Tanks (DG Fuel Oil Day Tank)	Pressure Boundary
Tanks (DG Fuel Oil Storage Tank)	Pressure Boundary
Tanks (Diesel Fire Pump Day Tank)	Pressure Boundary
Tanks (Jacket Water Expansion Tank)	Pressure Boundary
Tanks (Starting Air)	Pressure Boundary
Valve Body	Leakage Boundary Pressure Boundary

2.3.3.7 Emergency Filtration Train

Description

The HVAC System that serves the Main Control Room (MCR) and EFB is designed to provide cool air in the summer and warm air for heating in the winter. Ductwork is utilized to distribute air. The air flow in the MCR and portions of the EFB is normally pressurized with return air arranged to pass back to the air conditioning unit while supplemental outside air is drawn through the outside air ductwork. The EFT System can be manually placed into 100 percent recirculating mode if required. The air handling units are self-contained package units complete with electric coils for heating and cooling coils for air conditioning.

The EFT System will serve the MCR and EFB during normal or emergency conditions. An emergency condition is defined as that due to high radiation or detection of toxic chemical vapors in the outside air. During high radiation or detection of toxic chemicals, automatic or manual isolation of the Control Room Envelope (CRE) occurs; the CRE consists of the MCR and EFB first and second floors, excluding the battery room, and a portion of the third floor EFB.

In the normal operating mode, the MCR and EFB first, and second floors are served by one of the redundant Seismic Class 1 air conditioning units. The MCR and portions of the EFB ventilation are normally provided with outside air from the outside air ductwork. Upon receipt of an emergency signal (high radiation in the Reactor Building plenum or on the refueling floor, low-low reactor water level, drywell high pressure, or high radiation in the control room intake), dampers will automatically close, if not already closed, to isolate the CRE and a filtration train will automatically start to provide filtered outside air to the CRE.

Two emergency condition modes are defined for the EFT System, high radiation, and recirculation. During high radiation conditions, High Efficiency Particulate Filter (HEPA)/charcoal filtered outside air will pressurize the CRE so that contaminated air will not infiltrate. This arrangement is typical of those provided for BWRs with high off-gas stacks.

The recirculation mode is initiated when a toxic chemical release or other outside air contamination is detected in the control room air. For this mode, the EFT System will be manually placed in 100 percent recirculation, which isolates outside air intake, to provide unfiltered air to the MCR and EFB first, second and a portion of the third floors (excluding the Division II 250 Volts-Direct Current (VDC) Battery Room). No filtered air is supplied from the EFT during this condition, as certain chemicals can bypass or saturate the charcoal filters rendering them ineffective within a short time.

The EFT System normally operates from off-site power. If off-site power is not available, the system will be automatically supplied by the DGs.

Boundary

The EFT System boundaries are shown on the following SLRBDs:

SLR-36041
SLR-170037

System Intended Functions

SR components that perform SR functions (10 CFR 54.4(a)(1)):

(1) Provides a habitable environment for control room operators during post-accident conditions and supports SR equipment performance.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

None.

FP function (10 CFR 54.4(a)(3)):

(1) Performs function(s) relied upon for 10 CFR 50.48 regulation for FP, specifically to maintain habitability and controlled environment to support operator habitability and safe shutdown equipment performance.

USAR References

Section 6.7
Appendix J

Components Subject to AMR

Table 2.3.3-7 lists the EFT System component types that require AMR and their associated component intended functions.

Table 3.3.2-7 provides the results of the AMR.

Table 2.3.3-7
Emergency Filtration System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Blower Housing (EFT V-FE-11/12, EFT V-ERF-14A/14B, EFT V-EF-40A/40B, Inside V-EAC-14A/14B)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Bolting (HVAC Closure)	Mechanical Closure
Chiller (EFT V-EAC-14A/B)	Heat Transfer Pressure Boundary
Ducting and Components	Pressure Boundary
Heat Exchanger (EFT V-EAC-14A/B Condenser) Shell Side Components	Pressure Boundary
Heat Exchanger (EFT V-EAC-14A/B Condenser) Tubes	Heat Transfer Pressure Boundary
Heat Exchanger (EFT V-EAC-14A/B Condenser) Tube Side Components	Pressure Boundary
Heat Exchanger (EFT V-EAC-14A/B Condenser) Tubesheet	Pressure Boundary
Piping, Piping Components	Pressure Boundary

2.3.3.8 Emergency Service Water

Description

The ESW System includes the following three plant systems:

- Emergency Filtration-ESW System
- DGN-ESW System
- Residual Heat Removal Service Water (RHRSW) System

These plant systems are combined into the ESW System for SLR purposes. A description of each of the three systems is provided below.

The Emergency Filtration-ESW System consists of two separate and independent emergency cooling water loops that provide cooling water to the ECCS pump motor coolers, ECCS room coolers, and the emergency filtration train. Each loop is capable of providing cooling water during accident situations, loss of off-site power and/or a loss of normal service water. Each loop contains one full capacity pump that supplies cooling water to the cooling loads. One of the two divisions is capable of being controlled from the Alternate Shutdown (ASD) System panel for an Appendix R event. The Service and Seal Water (SSW) System is cross connected to the Emergency Filtration-ESW System. Cooling water from the SSW System normally flows to the cooling loads during normal plant operation.

The DGN-ESW System consists of two separate and independent emergency cooling water loops that provide cooling water to the EDGs. The loops are capable of providing cooling water during a loss of offsite power (LOOP) and during accident conditions. Each loop contains one full capacity pump that supplies cooling water to one of the EDGs. Cross-connect capability exists between the two loops. One of the two divisions is capable of being controlled from the ASDS panel for an Appendix R event. Each loop has a separate alternate supply from the SSW System.

The RHRSW System consists of two separate and independent emergency cooling water loops that provide cooling water to the RHR heat exchangers. Each loop is capable of providing cooling water during a loss of off-site power and during accident conditions. Each loop contains two pumps that supply cooling water through the tubes of the RHR heat exchangers. Train B is capable of being controlled from the ASDS panel for an Appendix R event. The RHRSW System is cross-connected to the SSW System, to the fire water system, and to the opposite loop of the RHRSW System, through a 1-inch pressurizing cross-tie line. The RHRSW System lines are pressurized during RHRSW System operation to maintain the pressure in the RHR heat exchanger tubes at a pressure greater than the pressure in the shell side.

The RHR auxiliary air compressors are included in the RHRSW System. These compressors provide a SR back-up air supply to the RHR heat exchanger service water outlet control valves (CV) upon occurrence of low pressure in the AIR System. The RHR auxiliary air compressors are normally in standby mode of operation.

Boundary

The Emergency Filtration-ESW System boundaries are shown on the following SLRBDs:

SLR-36041
SLR-36248
SLR-36664
SLR-36665
SLR-36807

The DGN-ESW System boundaries are shown on the following SLRBDs:

SLR-36664
SLR-36665

The RHRSW System boundaries are shown on the following SLRBDs:

SLR-36246
SLR-36247
SLR-36664
SLR-36665
SLR-36667

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide essential cooling for operation of ESF, the EDGs, and removal of decay heat through the RHR heat exchangers to achieve cold shutdown.

(2) Provide a SR back-up air supply to the RHR heat exchanger service water outlet CVs upon occurrence of low pressure in the AIR System.

(3) Maintain a higher pressure on the service water side of the RHR heat exchangers than the process side to prevent RHR process fluid leaks from being discharged into the river.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

(2) The ESW includes NSR SSCs necessary to complete the flowpath of cooling water through the Standby Diesel Generator coolers.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP and EQ.

USAR References

Section 10.4.2 and 10.4.4

Components Subject to AMR

Table 2.3.3-8 lists the ESW system component types that require AMR and their associated component intended functions.

Table 3.3.2-8 provides the results of the AMR.

Table 2.3.3-8
Emergency Service Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (RHR Aux Comp Air Receiver)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Heat Exchanger – (RHRSW Pump Motor Coolers) Shell Side Components	Pressure Boundary
Heat Exchanger – (RHRSW Pump Motor Coolers) Tubes	Heat Transfer Pressure Boundary
Hoses	Pressure Boundary
Insulated Piping, Piping Components	Pressure Boundary
Insulated Valve Body	Pressure Boundary
Orifice	Pressure Boundary Throttle
Piping, Piping Components	Pressure Boundary Leakage Boundary
Pump Casing (ESW/RHRSW)	Pressure Boundary
Strainer (Element)	Filter

Table 2.3.3-8
Emergency Service Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Valve Body	Pressure Boundary Leakage Boundary

2.3.3.9 Fire System

Description

The FIR System provides assurance that a fire will not prevent the performance of necessary safe-shutdown functions or significantly increase the risk of radioactive release to the environment during a postulated fire. The FIR System provides fire suppression by fixed water spray and sprinkler systems, fixed gas (Halon 1301) systems, hose stations, and portable extinguishers located in various areas of the MNGP site. MNGP has a fire detection and alarm system. The detectors in each fire area initiate an alarm locally and in the control room upon detecting either combustion or failure in the detector system.

The FIR System receives its water supply from the Mississippi River. Three vertical centrifugal pumps supply the fire suppression water subsystem. Two of these pumps are electric motor-driven and one is diesel-driven. One of the motor-driven pumps supplies the FIR System and is designated the fire pump. The other motor-driven pump normally supplies the screen wash system and is designated the screen wash/fire pump. Transfer from screen wash duty to fire duty occurs automatically.

All pumps are started automatically by instrumentation sensing header pressure. The jockey pump and/or the screen wash/fire pump is operated to maintain FP system header pressure greater than the electric motor-driven fire pump automatic start setpoint. Upon a drop of header pressure to 70 psig, the electric motor-driven fire pump and diesel-driven fire pump start. After a time delay, if the pressure in the system header remains at 70 psig or less, the screen wash/fire pump starts (if not initially running to maintain header pressure) as a third FIR System pump.

Any two pumps are capable of supplying firefighting water requirements in SR areas of the plant. The principal components of the FIR System are the main firewater loop, three fire pumps, jockey pump, hose stations, hydrants, hoses, spray/sprinkler heads, nozzles, and the associated piping, valves, and instrumentation to support the system's intended functions. Also included are the fixed Halon 1301 gas suppression system and the required gas cylinders, nozzles, and the associated piping, valves, and instrumentation to support the Halon subsystem's intended functions.

The FIR System also provides alternate sources of water to other plant systems. The FP water supply subsystem can provide water to the SSW System, and the RHRSW System, and can also provide makeup water to the SFP, if additional makeup is required. These secondary functions of the FIR System do not prohibit the system from performing its primary functions.

The Appendix R safe shutdown function applies to the FIR System components that provide for safe shutdown of the plant in the event of a fire. Appendix R components not specifically residing within the FIR System are addressed within the individual systems in which these components reside.

Fire damper housings, fire doors, penetration seals, etc., are not included in the FIR System and are evaluated as structural components. The fuel oil day-tank and fuel oil supply to the diesel-driven fire pump are addressed in the DGN System.

The FIR System components that (a) do not provide fire suppression capabilities for SR equipment or for equipment relied on for compliance with the regulations identified in the 10 CFR 54 scoping criteria, or (b) whose failure will not prevent the satisfactory performance of a SR function, are not included in the scope of LR. This includes the MNGP Training Center complex that is excluded from the scope of LR since it is outside the protected and owner controlled areas, is not connected to the main firewater loop, and is remote to the physical MNGP site.

The portions of the FIR System containing components subject to an AMR extend from the pump bays to the yard loops and include pumps, hose stations, hydrants, spray/sprinkler heads, nozzles, Halon gas cylinders, and associated piping, valves, and instrumentation.

In-scope fire detection and alarm devices are active components and are not subject to AMR. In-scope hose station fire hoses/nozzles and extinguishers are considered consumables that are routinely tested or inspected. The Fire Protection (B.2.3.15) program complies with the applicable NFPA safety standards, which specify performance and condition monitoring programs for these components. They are replaced as necessary and not subject to AMR.

<u>Boundary</u>

The FIR System boundaries are shown on the following SLRBDs:

SLR-36048
SLR-36048-2
SLR-36051
SLR-36516
SLR-36664
SLR-36665-2
SLR-36666
SLR-36667
SLR-170021
SLR-170037

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP.

USAR References

Section 10.3.1

Components Subject to AMR

Table 2.3.3-9 lists the FIR System component types that require AMR and their associated component intended functions.

Table 3.3.2-9 provides the results of the AMR.

Table 2.3.3-9
Fire System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Expansion Joints	Pressure Boundary
Fire Hydrant	Pressure Boundary
Heat Exchanger – (Diesel Fire Pump) Shell Side Components	Pressure Boundary
Heat Exchanger – (Diesel Fire Pump) Tube Sheet	Pressure Boundary
Heat Exchanger – (Diesel Fire Pump) Tube Side Components	Pressure Boundary
Heat Exchanger – (Diesel Fire Pump) Tubes	Heat Transfer Pressure Boundary
Hose Station Reels	Structural Support
Hoses (Pump and Drain Hoses)	Leakage Boundary Pressure Boundary
Orifice	Pressure Boundary Throttle
Piping Elements	Pressure Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary
Pump Casing (Fire System Jockey Pump)	Leakage Boundary
Spray Nozzles	Pressure Boundary Spray

Table 2.3.3-9
Fire System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Sprinklers	Pressure Boundary Spray
Strainer (Element)	Filter
Tank (Halon)	Pressure Boundary
Valve Body	Leakage Boundary Pressure Boundary

2.3.3.10 Fuel Pool Cooling and Cleanup

Description

The FPC System is designed to handle the spent fuel cooling load and to maintain pool water purity and clarity per USAR Section 10.2.2. The system provides sufficient filtering capacity to filter the entire spent fuel pool (SFP) water volume every 12 hours. The fuel pool temperature is normally maintained at 125°F or less in order to maintain a reasonable working environment in the pool area, to keep the demineralizer at an operable temperature, and to maintain visual clarity of the air above the pool. However, operation at temperatures up to 140°F is acceptable in order to remove decay heat from the spent fuel.

The FPC System consists of circulating pumps, heat exchangers, filter/demineralizers, piping, valves, tanks, and instrumentation. USAR Table 10.2-1 lists the design parameters of the principal equipment of this system. The pumps take suction from the skimmer surge tank, located at the top of the spent fuel storage pool water level, which continuously skims the water from the surface, and circulates the water to the heat exchangers, and filter/demineralizers before discharging the water through the diffusers at the bottom of the spent fuel pool. This arrangement of taking suction from the top and discharging to the bottom of the pool provides a cross flow which tends to sweep the pool and to carry off dirt and small particles. Foreign material entering the pool either sinks to the bottom to be removed by a portable vacuum cleaner or floats in the pool and eventually enters the skimmer surge tanks and filtering loop.

This system may also be used to drain the steam separator-dryer assemblies storage pit and the reactor head cavity after refueling. The lines permit draining the water to either the reactor building equipment drain tank or to the FPC System for processing, depending upon water condition. The fuel pool filters, and the skimmer surge tank are shielded with concrete. Provision is made for connecting to the RHR system to provide for additional backup heat removal capacity. The Liquid Radwaste System has a tie-in connection to the fuel pool filter-demineralizers. The fuel pool filter-demineralizers can be used as needed as a back-up for processing liquid waste.

The in-scope portion of the FPC System consists of the main cooling loops, including the skimmer surge tanks, pumps, heat exchangers, piping and valves located within the secondary containment (Reactor Building); as well as piping and valves to support draining of the dryer separator pool and reactor well. The FPC System filter/demineralizers and associated piping and valves located outside of the secondary containment (Reactor Building) are not within the scope of LR.

The majority of components in the FPC System are NSR and their failure could affect the capability of SR SSCs to perform their safety function; therefore, they are in-scope in accordance with 10 CFR 54.4(a)(2). The diffuser check valves (PC-20-1/2) are SR and are in-scope in accordance with 10 CFR 54.4(a)(1).

The FPC piping is designed such that failure of any piping does not drain the SFP. To protect against the possibility of a complete loss of water in the SFP, the suction line terminates near the top of the pool. The FPC System cooling water return line, which terminates lower in the pool, contains a check valve such that the pool water cannot be siphoned.

Boundary

The FPC System boundaries are shown on the following SLRBDs:

SLR-36042
SLR-36247
SLR-36256
SLR-36257
SLR-36908

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Prevent siphon backflow of spent fuel pool water.

(2) Maintain pressure boundary of the FPC System.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Sections 10.2.1 and 10.2.2

Components Subject to AMR

Table 2.3.3-10 lists the FPC System component types that require an AMR and their associated component intended functions.

Table 3.3.2-10 provides the results of the AMR.

Table 2.3.3-10
Fuel Pool Cooling and Cleanup System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Fuel Pool Cooling Heat Exchangers) Shell Side Components	Leakage Boundary
Heat Exchanger (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casings (Fuel Pool Cooling Water Pumps)	Leakage Boundary
Tanks (Skimmer Surge Tanks)	Leakage Boundary
Valve Body	Leakage Boundary Pressure Boundary

2.3.3.11 Heating and Ventilation

Description

The HTV System consists of the equipment required to affect and control the following space-air processes: supply and exhaust, distribution, and recirculation (where applicable), differential and static pressure control, filtration, cooling, and heating. It also includes sampling and fume hood exhausting and process tank venting.

The portion of the HTV System serving the RHR/CSP corner rooms is in-scope; the equipment is designed to provide cool air during normal operation and DBEs. The cooling ventilation removes heat produced by equipment, piping and motors while not causing SR equipment to become inoperable (i.e., water spray due to a coil leak). These air conditioning units are provided cooling water by the ESW system. The Reactor Building main supply units, also in-scope, are supplied coolant by an independent chilled water system, which in turn is cooled by the service and seal water (SSW) system.

The portion of the HTV System serving the HPCI Building is in-scope; the equipment is designed to provide cool air during normal operation and DBEs with the exception of the HPCI room air cooling units (V-AC-8A/B). V-AC-8A/B are not required for HPCI system operability but V-AC-8A provides normal means of maintaining room temperatures. V-AC-8B is normally isolated.

The RCIC System room cooler is also serviced by the SSW System with no provision for ESW cooling. The coil in this particular cooling unit, and the one in V-MZ-1, are in-scope for spatial interaction concerns.

Other room and equipment ventilation units in scope include the EDG ventilation dampers and supply fans. Reactor Building isolation dampers which close under secondary containment isolation conditions are included with the SCT System (Section 2.3.2.6).

General plant heating is provided by a piping network originating at the plant heating boiler and extending throughout most of the plant to supply heated water and/or steam to various unit heaters. Three notable locations not directly served are the drywell, Off-Gas Storage Building, and portions of the plant serviced by the EFT System.

Boundary

The HTV System boundaries are reflected on the following SLRBDs:

SLR-36033
SLR-36041
SLR-36259
SLR-36259-1
SLR-36259-2
SLR-36260
SLR-36261
SLR-36263
SLR-36266
SLR-36267-3
SLR-36267
SLR-36348
SLR-36664
SLR-36776
SLR-36807
SLR-36808
SLR-36881
SLR-46162
SLR-51142-1
SLR-67588

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The HTV System shall remove heat produced by equipment, piping, and motors for the RHR, CSP, HPCI, and DGN Systems during design basis events.

(2) Provide for controlled flow direction and release of radioactive gases during non-accident conditions.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for FP and EQ.

USAR References

Sections 5.3.4, 10.3.1, and 10.3.2

Components Subject to AMR

Table 2.3.3-11 lists the HTV System component types that require an AMR and their associated component intended functions.

Table 3.3.2-11 provides the results of the AMR.

Table 2.3.3-11
Heating and Ventilation System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Blower Housing (HPCI Room Air Cooling Units)	Pressure Boundary
Blower Housing (Reactor Building Main Exhaust Fan)	Pressure Boundary
Blower Housing (RHR Room Air Cooling Units)	Pressure Boundary
Blower Housing (Standby DG Room Supply Fan)	Pressure Boundary
Blower Housing (Turbine Building Operating Floor Air Handling Unit)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Bolting (HVAC Closure)	Mechanical Closure
Chillers (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary
Chillers (Reactor Building Chiller Evaporator) Shell Side Components	Leakage Boundary
Ducting and Components	HELB Barrier Flood Barrier Leakage Boundary Pressure Boundary Structural Integrity (Attached)
Heat Exchanger (Area Air Cooling Units) Shell Side Components	Leakage Boundary
Heat Exchanger (Area Air Cooling Units) Tube Side Components	Leakage Boundary
Heat Exchanger (Condensate Storage Heat Exchanger) Shell Side Components	Leakage Boundary
Heat Exchanger (Condensate Storage Heat Exchanger) Tube Side Components	Leakage Boundary
Heat Exchanger (HPCI/RHR/CSP Room Air Cooling Unit) Fins	Heat Transfer

Table 2.3.3-11
Heating and Ventilation System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heat Exchanger (HPCI/RHR/CSP Room Air Cooling Unit) Shell Side Components	Pressure Boundary
Heat Exchanger (HPCI/RHR/CSP Room Air Cooling Unit) Tube Side Components	Pressure Boundary
Heat Exchanger (HPCI/RHR/CSP Room Air Cooling Unit) Tubes	Heat Transfer Pressure Boundary
Heat Exchanger (Reactor Building Heating Coils) Shell Side Components	Leakage Boundary
Heat Exchanger (Reactor Building Heating Coils) Tube Side Components	Leakage Boundary
Heat Exchanger (Reactor Building Main Supply HVAC Unit Heating Coil) Shell Side Components	Leakage Boundary
Heat Exchanger (Reactor Building Main Supply HVAC Unit Heating Coil) Tube Side Components	Leakage Boundary
Heat Exchanger (Reactor Building Main Supply HVAC Unit, Cooling Coil) Shell Side Components	Leakage Boundary
Heat Exchanger (Reactor Building Main Supply HVAC Unit, Cooling Coil) Tube Side Components	Leakage Boundary
Heat Exchanger (Steam Chase Supply Cooling Coil) Shell Side Components	Leakage Boundary
Heat Exchanger (Steam Chase Supply Cooling Coil) Tube Side Components	Leakage Boundary
Heat Exchanger (Turbine Building Reheaters) Shell Side Components	Leakage Boundary
Heat Exchanger (Turbine Building Reheaters) Tube Side Components	Leakage Boundary
Heat Exchanger (Unit Heaters) Shell Side Components	Leakage Boundary
Heat Exchanger (Unit Heaters) Tube Side Components	Leakage Boundary
Hoses	Leakage Boundary
Insulated Piping, Piping Components	Leakage Boundary
Insulated Pump Casing (Reactor Building Chilled Water Pump)	Leakage Boundary
Insulated Valve Body	Leakage Boundary
Piping Elements	Leakage Boundary
Piping, Piping Components	Leakage Boundary
Pump Casing (Condensate Return)	Leakage Boundary
Tanks (Chilled Water Expansion Tank)	Leakage Boundary
Tanks (Condensate Return Tanks, Intake/Turbine/Reactor Building)	Leakage Boundary
Valve Body	Leakage Boundary

2.3.3.12 Instrument and Service Air

Description

The plant AIR system provides the plant with a continuous supply of oil-free compressed air. Dry air is supplied to plant instruments and controls as required and is provided at hose stations throughout the plant.

The AIR System includes three non-lubricated, variable speed drive air compressors, each with an intake filter, air cooler, moisture separator/trap and associated dryer and receiver. The compressors are controlled from a common control panel and associated system header pressure transmitters to allow for any combination of lead or standby function of each compressor as desired. In addition to this common control panel, each compressor can be controlled from its integral controller and discharge pressure transducer. Normally, one air compressor is in the lead position and the others are in standby as controlled by the common control panel.

The three compressors discharge air to their respective air dryers through aftercoolers with moisture separator/traps. Each compressor is cooled by its dedicated ethylene glycol closed cooling system. The air dryers supply the air receivers and the AIR System. The receivers act as a surge volume to minimize the effects of pressure surges caused by usage, and the loading and unloading of the compressors. Flow measuring instrumentation allows monitoring of compressor performance and instrument and service air usage.

The air for the AIR System is dried by means of twin bed desiccant type air dryers, each installed between a pre-filter and after-filter. When one bed of a dryer is in service, the alternate bed is in standby. When a dryer senses too high of a moisture content in the standby bed, it will automatically put that bed in the regenerating cycle. The beds are alternated in service to provide a continuous flow of dry air to the system. An after-filter is located downstream of each dryer to trap any particulates which pass through or are released by the compressors or air dryers.

The instrument air portion of the AIR System supplies the compressed air requirements for most pneumatic instruments and controls located throughout the plant. The service air portion of the AIR System consists mainly of a piping system which supplies hose stations throughout the plant and is intended for various miscellaneous usages by maintenance and operations personnel.

In addition to the AIR System, there are other pneumatic systems in the plant. These systems are not part of this AMR. The other pneumatic systems include an outboard main steam isolation valve air supply which is part of the MST System, an AN2 System which is a separate mechanical system, an instrument N_2 supply to containment which is part of the PCM System, and the control room breathing air system which is part of the EFT System. Furthermore, one of the AIR System requirements is to provide PCT isolation. These sections of piping, which pass through the PCT, may experience slightly different operating conditions than those of the aggregate piping system.

Boundary

The AIR System boundaries are shown on the following SLRBDs:

SLR-36049-4
SLR-36049-10
SLR-36049-12
SLR-36049-14
SLR-36258
SLR-161004

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides primary containment isolation for those portions of the system that interface with the primary containment (valves and piping).

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for EQ.

USAR References

Section 10.3.4

Components Subject to AMR

Table 2.3.3-12 lists the AIR System component types that require AMR and their associated component intended functions.

Table 3.3.2-12 provides the results of the AMR.

Table 2.3.3-12
Instrument and Service Air System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Piping, Piping Components	Pressure Boundary Structural Integrity (Attached)
Valve Body	Pressure Boundary Structural Integrity (Attached)

2.3.3.13 Radwaste Solid and Liquid

Description

The RAD System comprises the solid radwaste subsystem and the liquid radwaste subsystem. The Solid Radwaste System is designed to process, package, store, monitor, and provide shielded storage facilities for solid radioactive wastes to allow for radioactive decay and/or temporary storage prior to shipment for off-site disposal.

The Liquid Radwaste System is designed to collect, process, and dispose of all radioactive liquid wastes generated during operation of the plant. The system is designed to accommodate the radioactive input resulting from the design basis maximum fuel leakage condition. Liquid wastes from various drains and discharges from the reactor process and auxiliary systems are processed through the Liquid Radwaste System. Liquid wastes are collected in sumps and drain tanks in the various buildings and then transferred to the appropriate subsystem collection tanks in the Radwaste Building for subsequent treatment and disposal.

In order to keep liquid radwaste releases to a minimum, modifications were made to the Liquid Radwaste System to allow reclaiming of floor drains as well as equipment drains. The modified system limits the release of liquid effluents to the minimum practicable amount to satisfy the Design Objectives of Appendix I to 10 CFR Part 50.

The radioactive and chemical contaminants are removed from the liquid waste streams by either filtration or filtration followed by mixed deep-bed demineralization. The filters remove insoluble particulate contaminants, and the demineralizer is used to remove soluble materials. The filter and demineralizer sludge are back washed into receiving tanks, dewatered, and packaged as solid waste for disposal off-site at NRC approved sites.

All RAD System components existing in either the Turbine Building (TGB) or Reactor Building (RB), and constituting a liquid pressure boundary, are in-scope. This includes piping, valve bodies, tanks, pump casings, orifices, drains, heat exchangers and fasteners.

Boundary

The RAD System boundaries are shown on the following SLRBDs:

SLR-36035-2
SLR-36038-3
SLR-36043
SLR-36044
SLR-36045
SLR-36046
SLR-36047-1
SLR-36241
SLR-36247
SLR-36248
SLR-36908

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides primary containment isolation for those portions of the system that interface with primary containment.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

(2) The RAD System is in scope for the (a)(2) intended function of “holdup and plateout” as a result of the implementation of AST for the analysis of the control rod drop accident.

FP, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) The RAD System contains components that are required for EQ per 10 CFR 50.49.

USAR References

Sections 5.2, 9.2, and 9.4

Components Subject to AMR

Table 2.3.3-13 lists the RAD System component types that require an AMR and their associated component intended functions.

Table 3.3.2-13 provides the results of the AMR.

Table 2.3.3-13
Radwaste Solid and Liquid System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Drywell Equip Drain Sump) Shell Side Components	Leakage Boundary
Heat Exchanger (Drywell Equip Drain Sump) Tube Side Components	Leakage Boundary
Orifice	Leakage Boundary Throttle
Piping, Piping Components	Holdup and Plateout Leakage Boundary Pressure Boundary Structural Integrity (Attached)

Table 2.3.3-13
Radwaste Solid and Liquid System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Pump Casing (DW Equipment Drain Sump/RB Equipment Drain Sump/ TB Equipment Drain Sump/Condensate Drip Tank/DW Floor Drain Sump/Condensate Pump Area Sump/Condensate Backwash/RB Equipment Drain Tank)	Leakage Boundary
Pump Casing (RB Floor Drain Sump/RB Floor Drain Tank/TB Floor Drain Sump/ECCS Area Drain)	Pressure Boundary
Tanks (Air Surge Volume)	Leakage Boundary
Tanks (Condensate Backwash Receiving)	Holdup and Plateout Leakage Boundary
Tanks (Machine Shop Drain)	Leakage Boundary
Tanks (RB Equipment Drain/Condensate Drip)	Leakage Boundary
Tanks (RB Floor Drain)	Pressure Boundary
Valve Body	Holdup and Plateout Leakage Boundary Structural Integrity (Attached) Pressure Boundary

2.3.3.14 Reactor Building Closed Cooling Water

Description

The RBC System is designed to remove heat from the reactor auxiliary systems' equipment including:

- CRD System pump coolers
- Drywell coolers
- Fuel Pool Cooling and Demineralizer System heat exchangers
- PCM System post-accident sampling coolers
- RAD System drywell equipment drain sump heat exchanger
- Reactor Building and Turbine Building process system sample coolers and chillers
- Reactor recirculation system pump motor and seal water coolers
- RWC System non-regenerative heat exchangers
- RHR System pump seal coolers

The RBC System consists of a chemically treated closed cooling water loop containing two pumps and three heat exchangers in parallel, and the associated piping, valves, and instrumentation. The pumps discharge into a common header that supplies the three RBC heat exchangers. This flow is then distributed to the various reactor auxiliary systems' heat exchangers. The system temperature is maintained by heat rejection from the RBC System heat exchangers to the

SSW System. The RBC System is monitored continuously for radioactivity by a process radiation monitor.

Boundary

The RBC System boundaries are shown on the following SLRBDs:

SLR-36042
SLR-36042-2
SLR-36044
SLR-36243-1
SLR-36254
SLR-96042-1

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides primary containment isolation for those portions of the system that interface with primary containment.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, PTS, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) The RBC System contains components that are required for EQ per 10 CFR 50.49.

USAR References

Sections 5.2 and 10.4.3

Components Subject to AMR

Table 2.3.3-14 lists the RBC System component types that require an AMR and their associated component intended functions.

Table 3.3.2-14 provides the results of the AMR.

Table 2.3.3-14
Reactor Building Closed Cooling Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Drywell Coolers) Tubes	Leakage Boundary
Heat Exchanger (RB Cooling Water) Shell Side Components	Leakage Boundary

Table 2.3.3-14
Reactor Building Closed Cooling Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heat Exchanger (RB Cooling Water) Tube Side Components	Leakage Boundary
Hoses	Leakage Boundary
Insulated Piping, Piping Components	Leakage Boundary
Insulated Valve Body	Leakage Boundary
Piping Elements	Leakage Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (Reactor Building Cooling Water Pumps)	Leakage Boundary
Tanks (Chemical Feeder)	Leakage Boundary
Tanks (Reactor Building Cooling Water Surge Tank)	Leakage Boundary
Valve Body	Leakage Boundary Pressure Boundary

2.3.3.15 Reactor Water Cleanup

Description

The RWC System is a filtering and ion exchange system that maintains water purity in the reactor and recirculation lines during all modes of plant operation. This minimizes changes in the core heat transfer characteristics by reducing the deposition of impurities on fuel surfaces by lessening the amounts of water-borne impurities in the reactor primary system. It also reduces sources of beta and gamma radiation by removing corrosion products, fission products, and impurities in the reactor primary system. The RWC System provides for primary containment isolation and is also isolated on initiation of the Standby Liquid Control (SLC) System or upon indication of high RWC System flow. The valves which provide for primary containment isolation are included in the RCPB and Connected Piping System.

The RWC System provides for continuous purification of a portion of the reactor Recirculation (REC) System flow with a minimum of heat loss and water loss from the cycle. Water is normally removed at reactor pressure from one of the REC System loops and from the RPV bottom head drain, and then cooled in the regenerative and non-regenerative heat exchangers, filtered, demineralized, and pumped through the shell side of the regenerative heat exchangers to raise the temperature before returning it to the RPV. The non-regenerative heat exchangers use cooling water from the RBC System to cool the incoming water. System water may be directed to the main condenser or to the RAD System. The RWC System has been modified since initial LR to include a sampling loop in support of the Online Noble Metal Chemistry Injection System. The online noble chemistry system injects a platinum compound the feedwater system to mitigate intergranular stress corrosion cracking. The associated sampling loop installed in the RWC System monitors the effectiveness of the injected platinum solution.

Boundary

The SLR boundaries for the RWC System are reflected on the SLRBDs listed below. The interfaces between the RWC System and other systems are identified on the SLRBDs. The only significant difference between these boundaries and the initial LR system boundaries is shown on SLR-36254. The boundary between the RWC and the RCPB and Connected Piping System (Section 2.3.1.3) has been moved to just outboard of containment isolation valves. All RWC components inboard of these valves are now part of the RCPB and Connected Piping System. The RWC System boundaries are shown on the following SLRBDs:

SLR-36254
SLR-36255
SLR-252182
SLR-74945-3

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The RWC System includes SR environmentally qualified flow instrumentation that automatically isolates the RWC System from the RCPB upon indication of an RWC System line break.

(2) The RWC System includes SR piping and check valves at the interfaces with the high pressure coolant injection and reactor core isolation cooling systems.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the EQ program, ATWS, and FP.

USAR References

Section 10.2.3

Components Subject to AMR

Table 2.3.3-15 lists the RWC System component types that require AMR and their associated component intended functions.

Table 3.3.2-15 provides the results of the AMR.

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

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Non-Regenerative) Shell Side Components	Leakage Boundary
Heat Exchanger (Non-Regenerative) Tube Side Components	Leakage Boundary
Heat Exchanger (Regenerative) Shell Side Components	Leakage Boundary
Heat Exchanger (Regenerative) Tube Side Components	Leakage Boundary
Orifice	Pressure Boundary Throttle
Piping, Piping Components	Pressure Boundary Leakage Boundary
Pump Casing (Cleanup Recirc Pumps)	Leakage Boundary
Valve Body	Pressure Boundary Leakage Boundary

2.3.3.16 Service and Seal Water

Description

The SSW System provides cooling water to equipment in the INS, Reactor Building, and Turbine Building.

The Service Water System consists of three pumps, an auto strainer, bypass basket strainer, associated valves, piping, and instrumentation. Normal system operation requires two pumps, however, during the cold winter months, only one pump is required. One pump is normally placed in auto-standby.

The Seal Water System consists of two pumps with upstream filter units utilizing a domestic water source backed up by service water, to provide clean water to various pump seals on site. Pumps provided seal water include circulating water, cooling tower, and fire pumps as well as the four RHR pumps.

The Biocide Injection System (BIS), which is a subsystem of the SSW System, consists of two chemical pumping skids with local manual start control, two chemical supply tanks, and distribution tubing to the process systems. The tanks and pumps are located in the Sodium Hypochlorite Building and piped to the distribution tubing and the process lines in the INS. One skid is used to inject the non-oxidizing biocide and the other skid injects a dispersant into the target systems. The BIS components leaving the pumping skids have been donated to the SSW System.

The stainless steel (SS) tubing from each injection pump branches to the individual process pipes for RHR service water (RHRSW), ESW and the FIR Systems. Each process pipe connection has an isolation valve that is closed when injection is completed. A check valve separates the NSR BIS from the SR or FP related process pipe to assure the integrity of the process system. Biocide and dispersant are injected simultaneously into the target system, but through separate injection connections.

Boundary

The SSW System boundaries are shown on the following SLRBDs:

SLR-36035-2
SLR-36037-3
SLR-36041-2
SLR-36041
SLR-36048
SLR-36050
SLR-36052
SLR-36489
SLR-36664
SLR-36665-2
SLR-36665-3
SLR-36665
SLR-36666-2
SLR-36666
SLR-36667
SLR-36807
SLR-155483-1

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function. The SSW System provides a discharge flowpath for SR components supplied by RHRSW or ESW.

(2) The SSW System contains structures and/or components whose failure could cause failure of SR components due to spatial interactions.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) The SSW System contains components that are required per 10 CFR 50.48. The SSW System is connected to the FIR System, and certain SSW System valves provide a pressure boundary to prevent backflow from the FIR System.

USAR References

Section 10.4.1

Components Subject to AMR

Table 2.3.3-16 lists the SSW System component types that require an AMR and their associated component intended functions.

Table 3.3.2-16 provides the results of the AMR.

Table 2.3.3-16
Service and Seal Water System **Components Subject to Aging Management Review**

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Expansion Joints	Leakage Boundary
Heat Exchanger - (Recirc MG Set Oil Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger - (Recirc MG Set Oil Cooler) Tube Side Components	Leakage Boundary
Hoses	Leakage Boundary
Insulated Piping, Piping Components	Leakage Boundary
Insulated Valve Body	Leakage Boundary
Piping Elements	Leakage Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (Seal Water Pump)	Leakage Boundary
Pump Casing (Service Water Pump)	Leakage Boundary
Pump Casing (Service Water Radiation Monitor Sample Pump)	Leakage Boundary
Valve Body	Leakage Boundary Pressure Boundary

2.3.3.17 Standby Liquid Control

Description

The SLC System provides a means of inserting negative reactivity into the reactor core by the injection of neutron absorbing boron in the form of liquid sodium pentaborate. A key lock switch that starts the SLC System pumps and opens the squib-operated valves provides control of injection. The boron solution is capable of shutting down the reactor and providing a sufficient shutdown margin to overcome void and temperature coefficients, as well as the effects of xenon, assuming that none of the withdrawn control rods can be inserted. Service air and demineralized water are provided to the SLC tank for mixing of the boron solution, as well as instrument air to various instrumentation.

The SLC System also provides for primary containment isolation, but Class 1 boundary components that carry a SLC equipment designation are addressed in the RCPB and Connected Piping System along with any other SLC components inboard of containment isolation valve XP-6.

Boundary

The SLR boundaries for the SLC System are reflected on the SLRBDs listed below. The interfaces between the SLC System and other systems are identified on the SLRBDs. The only significant difference between these boundaries and the initial LR system boundaries is shown on SLR-36242-1 and SLR-36253. The boundary between the SLC and the RCPB and Connected Piping System (Section 2.3.1.3) has been moved to just outboard of the containment isolation valves. All SLC components inboard of these valves are now part of the RCPB and Connected Piping System.

SLR-36242-1
SLR-36253

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Bring the reactor to a shutdown condition at any time in the reactor core life, even if any or all withdrawn control rods are unavailable for insertion.

(2) Mitigate the radiological consequences of a design basis accident LOCA by maintaining suppression pool pH greater than 7 through injection of sodium pentaborate solution

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulations for the ATWS program.

USAR References

Section 6.6

Components Subject to AMR

Table 2.3.3-17 lists the SLC System component types that require AMR and their associated component intended functions.

Table 3.3.2-17 provides the results of the AMR.

Table 2.3.3-17
Standby Liquid Control System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Accumulator (Standby Liquid Control Accumulator)	Pressure Boundary
Bolting (Closure)	Mechanical Closure
Drip Pan	Leakage Boundary
Hoses	Leakage Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (Standby Liquid Control Pump)	Pressure Boundary
Tanks (Standby Liquid Control Tank)	Pressure Boundary
Tanks (Standby Liquid Control Test Tank)	Leakage Boundary
Valve Body	Leakage Boundary Pressure Boundary

2.3.3.18 Wells and Domestic Water

Description

The WDW System includes the domestic water, sanitary sewer, acid drain, storm drain, and Turbine Building normal drain subsystems.

The domestic water subsystem supplies well water to the DWS, the SSW System, hot and/or cold water to lavatories, the laundry, showers, etc., throughout the plant's protected area.

The sanitary sewer system removes wastewater from lavatories, showers, sinks, etc., in the protected area, Administration Building, and warehouse #5. It carries the wastewater to the City of Monticello sewage system.

The acid drain system removes water from such things as the DWS area drain and heating boiler blowdown which is unfit for direct discharge to the river. Drainage from these sources is carried to the discharge retention basin where it is treated and monitored before release to the river.

The storm drain system carries water from building roofs and normal surface drainage to the river.

The Turbine Building normal drain subsystem removes water from areas in the Turbine Building where there is no potential for radioactive contamination and transports it to the river.

The WDW System is in-scope for LR because of check valves and connected piping located in the floor drain lines of both EDG rooms. The valves are located below the surface of the floor and are accessible through bolted access covers located at floor level in the 11 EDG room. The valves and connected piping function to 1) prevent flooding in one EDG room from causing flooding in the other EDG room, 2) provide assurance that combustibles from one EDG room will not be transferred to the other EDG room, and 3) prevent Turbine Building normal waste sump discharge from flooding EDG rooms.

There are also components in the WDW System whose failure could affect the capability of SR SCs to perform their safety function. This includes domestic water piping located in the Turbine Building, EFB, cable spreading room, and MCR. Also included in this category are roof drains and clean (non-radioactive) floor drains not buried in concrete or ground, located throughout the plant. Potentially radioactive floor drains are included in the RAD System.

The portions of the WDW System containing components subject to an AMR include the check valves and connected floor drain piping located in the EDG rooms, domestic water piping located in the Turbine Building, EFB, cable spreading room, and MCR; and roof drains and clean (non-radioactive) floor drains not buried in concrete or ground, located throughout the plant.

Boundary

The SLR boundaries for the WDW System are reflected on the SLRBDs listed below. The interfaces between the WDW System and other systems are identified on the SLRBDs. There are no significant differences between these boundaries and the initial LR system boundaries as shown on:

SLR-36044
SLR-155483-1

The SLR boundaries of the WDW System shown on the SLRBDs include components that form the system boundaries with the systems listed below:

- SSW System (Section 2.3.3.16)
- DWS system (Section 2.3.3.5)
- RAD System (Section 2.3.3.13)

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) The WDW System contains components that perform a function that demonstrates compliance with FP program requirements.

USAR References

Sections 10.3.5 and 10.3.6.2.4

Components Subject to AMR

Table 2.3.3-18 lists the WDW System component types that require AMR and their associated component intended functions.

Table 3.2.2-18 provides the results of the AMR.

Table 2.3.3-18
Wells and Domestic Water System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Piping, Piping Components	Pressure Boundary Leakage Boundary
Pump Casing (Turbine Building Normal Waste Sump)	Leakage Boundary
Valve Body	Pressure Boundary Leakage Boundary

2.3.4 Steam and Power Conversion System

2.3.4.1 Condensate Storage

Description

The CST System provides a large storage capacity of reactor quality water. The CST System is normally operating continuously during normal plant operation for power generation. The normal plant uses for CST water are as follows:

(1) Hotwell makeup and reject
(2) Control rod drive supply
(3) Fuel storage pool makeup
(4) Demineralizer and radwaste processing
(5) Filling the refueling wells
(6) Miscellaneous plant flushing and decontamination services
(7) Pressurizing RHR and CSP piping
(8) Normal suction supply for HPCI and RCIC Systems

For a SBO event, the required condensate inventory for decay heat removal calculated using the method of NUMARC 87-00 Section 7.2.1 is 44,329 gallons. This value is within the available CST tank inventory. The available CST tank inventory provides adequate water volume to remove decay heat and maintain reactor vessel level above the top of active fuel.

Boundary

The CST System boundaries are shown on the following SLRBDs:

SLR-36033
SLR-36035-2
SLR-36036
SLR-36039
SLR-36045
SLR-36047-1
SLR-36244
SLR-36246
SLR-36247
SLR-36248
SLR-36250
SLR-36252
SLR-36255
SLR-36256
SLR-36257
SLR-36260
SLR-85509

The CST System now includes the CST tanks (T-1A and B) as in-scope for SLR per 10 CFR 54.4(a)(3) for SBO.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) On low CST tank level, a signal is provided automatically to transfer HPCI and RCIC water supplies from the CST tanks to the suppression pool.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function in accordance with 10 CFR 54.4(a)(2).

(2) Maintaining the CSP and RHR systems pressurized is needed to maintain core spray and RHR system operability.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commissions' regulations for EQ and SBO.

USAR References

Sections 6.2.4.2.2. 6.2.4.2.11, 8.12, 10.2.5, and 14.7.2.3

Components Subject to AMR

Table 2.3.4-1 lists the CST System component types that require an AMR and their associated component intended functions.

Table 3.4.2-1 provides the results of the AMR.

Table 2.3.4-1
Condensate Storage System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Expansion Joints	Pressure Boundary
Insulated Piping, Piping Components	Pressure Boundary
Insulated Tanks (Condensate Storage Tank)	Pressure Boundary
Insulated Valve Body	Pressure Boundary
Piping Elements	Pressure Boundary
Piping, Piping Components	Leakage Boundary Pressure Boundary
Pump Casing (Condensate Service Jockey Pump)	Pressure Boundary
Pump Casing (Condensate Service Pump)	Pressure Boundary

Table 2.3.4-1
Condensate Storage System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Pump Casing (High Pressure Decontamination Pump)	Leakage Boundary
Valve Body	Leakage Boundary Pressure Boundary

Note: ½-in hose and lance shown at coordinate (B,1) of SLR-36256 Revision 0 are short-lived and replaced based on condition.

2.3.4.2 Condensate and Feedwater

Description

The CFW System supplies condensate from the main condenser to the reactor vessel at an elevated temperature and pressure. Two motor-driven condensate pumps pump condensate through the steam jet air ejector inter-condensers and the steam packing exhauster. After leaving the steam packing exhauster, condensate passes through the full-flow condensate demineralizers. Effluent, from the demineralizers, splits into two parallel paths, each with three stages of low-pressure feedwater heating, to the suction of the reactor feedwater pumps. The flow from each of the two motor-driven reactor feedwater pumps splits into two parallel paths, each with two stages of high-pressure heating, and then to the reactor vessel.

The two feedwater lines that penetrate primary containment are provided with check valves to prevent backflow from the reactor through the feedwater lines. Once through primary containment, the lines divide into four headers which supply the feedwater sparger ring inside the reactor vessel. The feedwater vessel nozzles are evaluated in the reactor pressure vessel AMR (Section 2.3.1.1), and the Class 1 piping is evaluated in the RCPB and connected piping AMR (Section 2.3.1.3). The HPCI, RCIC and RWC Systems also discharge into the feedwater lines upstream of the two primary containment isolation check valves. The CFW System is credited for use in the SBO regulated event for the HPCI injection flowpath.

Boundary

The CFW System boundaries are shown on the following SLRBDs:

SLR-36034
SLR-36035
SLR-36036
SLR-36037-2
SLR-36037-3
SLR-36037
SLR-36038-1
SLR-36038-2
SLR-36038-3
SLR-36038
SLR-36039

SLR-36041
SLR-36044
SLR-36047-1
SLR-36241
SLR-54817-4
SLR-85509
SLR-100320
SLR-11929
SLR-252182
SLR-236609

There are several differences between the initial LR CFW System boundary and the SLR CFW System boundary. Portions of the system boundary now include the intended function of holdup and plateout in support of AST implementation. Additionally, all Class 1 piping and valves originally in the initial LR condensate and feedwater boundary have been moved to the RCPB and Connected Piping System (Section 2.3.1.3).

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) The CFW System is in scope for the (a)(2) intended function of "holdup and plateout" as a result of the implementation of AST methodology.

(2) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Perform a function that demonstrates compliance with the Commission's regulation for SBO.

USAR References

Section 11.7 and 11.8

Components Subject to AMR

Table 2.3.4-2 lists the CFW System component types that require an AMR and their associated component intended functions.

Table 3.4.2-2 provides the results of the AMR.

Table 2.3.4-2
Condensate and Feedwater System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Expansion Joints	Leakage Boundary
Heat Exchanger (Condensate Pump Motor Upper and Lower Bearing Cooler) Tubes	Leakage Boundary
Heat Exchanger (FW Heater) Shell Side Components	Leakage Boundary
Heat Exchanger (FW Heater) Tube Side Components	Leakage Boundary
Heat Exchanger (FW Heater Drain Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger (FW Heater Drain Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger (RFP Lubricating Oil Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger (RFP Lubricating Oil Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger (RFP Motor Cooler) Tube Side Components	Leakage Boundary
Hoses	Leakage Boundary
Piping, Piping Components	Holdup and Plateout Leakage Boundary
Pump Casing (Body Feed Pump)	Leakage Boundary
Pump Casing (Condensate Demineralizer Holding Pump)	Leakage Boundary
Pump Casing (Condensate Pump)	Leakage Boundary
Pump Casing (Main Lubricating Oil Pump)	Leakage Boundary
Pump Casing (Precoat Injection Pump)	Leakage Boundary
Pump Casing (Precoat Recycle Pump)	Leakage Boundary
Pump Casing (Reactor Feed Pump)	Leakage Boundary
Pump Casing (RFP Seal Drain Tank Pump)	Leakage Boundary
Tanks (Auxiliary Tank)	Leakage Boundary
Tanks (Body Feed Tank)	Leakage Boundary
Tanks (Condensate Demineralizer Tank)	Leakage Boundary
Tanks (Dissolution Column)	Leakage Boundary
Tanks (Precoat Tank)	Leakage Boundary
Tanks (RFP Seal Drain Tank)	Leakage Boundary
Tanks (RFP Lubricating Oil Tank)	Leakage Boundary
Valve Body	Holdup and Plateout Leakage Boundary

2.3.4.3 Main Condenser

Description

The CDR System provides a heat sink for the steam cycle, removes non-condensable gases, and serves as a central collection point for system drains. The CDR System is NSR but is credited in USAR LOCA analyses and control rod drop accident analyses for post-accident iodine plate out and holdup.

The CDR System consists principally of the main condenser which condenses steam exhausted from the turbine and turbine bypass system. The main condenser is a twin shell, dual pressure surface condenser. Each of the two low-pressure turbines exhausts into its side of the twin shell. The steam is distributed throughout the steam space of the condenser shell and enters the tube bank where it comes in contact with the outer tube surface. Circulating raw water from the Mississippi River flowing inside the tubes keeps the tubes at a lower temperature than the saturation temperature of the steam. Because of the temperature difference, heat is transferred from the steam through the tube wall to the circulating water causing the steam to condense on the tubes. The series arrangement of the flow of circulating water through the condenser twin shell results in each shell operating at different pressures. The inlet (cold) water from the circulating water pumps passes through the first shell and then the same water (at an elevated temperature) is directed through the second shell. The colder water produces a lower turbine exhaust pressure in the first shell. The series CWT System, associated with a twin shell condenser, results in a lower average turbine exhaust pressure than the more conventional single pressure condenser with a parallel CWT System. An additional improvement in the cycle performance is achieved by directing the condensate flow from the low-pressure (cold) shell to the high-pressure (hot) shell for reheating to the temperature corresponding to the saturation temperature in the high-pressure shell.

The components for the CDR System are located in the Turbine Building. The system components are made of stainless steel, carbon steel, copper alloy, elastomer, and glass. The CDR System is normally operating continuously during normal plant operation for power generation.

The portions of the CDR System containing components subject to an AMR include the closure bolting, expansion joints, heat exchangers, Low Pressure (LP) turbine hood, piping elements, piping and piping components, pump casings, tanks, and valve bodies located within the Turbine Building.

Boundary

The CDR System boundaries are shown on the following SLRBDs:

SLR-36033
SLR-36034
SLR-36035-2
SLR-36035
SLR-36036
SLR-36041

SLR-54817-4
SLR-54818-1

The major difference between the initial LR CDR System boundary and the SLR CDR System boundary is that the equipment originally identified with a component intended function of pressure boundary is now in scope with a function of leakage boundary, holdup and plateout, as well as pressure boundary.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide isolation of the mechanical vacuum pump when high radiation signal is generated from the main steam line radiation monitors.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) The NSR MSIV leakage to main condenser drain pathway is in-scope in accordance with 10 CFR 54.4(a)(2) for iodine plate-out during hypothetical design basis accidents.

(2) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function in accordance with 10 CFR 54.4(a)(2).

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Sections 11.3 and 14.7.1.6.3

Components Subject to AMR

Table 2.3.4-3 lists the CDR System component types that require an AMR and their associated component intended functions.

Table 3.4.2-3 provides the results of the AMR.

Table 2.3.4-3
Main Condenser System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Expansion Joints	Leakage Boundary Holdup and Plateout
Heat Exchanger (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Leakage Boundary Holdup and Plateout
Heat Exchanger (Condenser Mech Vac Pump Seal Water Cooler) Tube Side Components	Leakage Boundary Holdup and Plateout

Table 2.3.4-3
Main Condenser System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heat Exchanger (Main Condenser) Shell Side Components	Leakage Boundary Holdup and Plateout
Heat Exchanger (Main Condenser) Tubes	Holdup and Plateout
Heat Exchanger (Main Condenser) Tubesheet	Holdup and Plateout
LP Turbine Hood	Leakage Boundary Holdup and Plateout
Piping Elements	Leakage Boundary Holdup and Plateout
Piping, Piping Components	Leakage Boundary Holdup and Plateout Pressure Boundary
Pump Casings (Condenser Mechanical Vacuum Pump)	Leakage Boundary Holdup and Plateout
Pump Casings (MVP Recirculation Seal Pump)	Leakage Boundary Holdup and Plateout
Tanks (MVP Moisture Separator Tank)	Leakage Boundary Holdup and Plateout
Valve Body	Leakage Boundary Holdup and Plateout Pressure Boundary

2.3.4.4 Main Steam

Description

The MST System transports steam produced in the reactor to the main turbine for the production of electricity. This steam is supplied to the high pressure section of the turbine. Steam leaving the high pressure turbine is divided; the bulk of it passing through moisture separators prior to admission to the low pressure sections. A portion of the steam is extracted and is condensed as it is cascaded through feedwater heaters enroute to the main condenser. Normally, the turbine utilizes all the steam being generated by the reactor. However, automatic pressure-controlled bypass valves are supplied which can discharge excess steam directly to the condenser. The MST System, between the MSIVs and the turbine stop valves (TSV), consists of the piping necessary to direct steam to various systems and components such as the main turbine, turbine bypass valves, steam jet air ejectors, off-gas recombiners, turbine steam seal system, and condenser deaerator. Drains are provided to remove condensate from the steam lines.

MST System piping from the RPV up to and including the outboard MSIV on each of the four main steam lines is included in the scope of the RCPB and Connected Piping System (Section 2.3.1.3). The SLR RCPB and Connected Piping System contains all ASME Class 1 piping, piping components, and valves outboard of the reactor vessel nozzles including those components from the MST System. The MST portion of the RCPB and Connected Piping System supplies steam to the high pressure coolant injection and reactor core isolation cooling turbines. It also includes the in-line flow restrictor for each of the four main steam lines. These flow restrictors minimize reactor coolant losses and protect the fuel barrier prior to MSIV closure for steam line ruptures outside of primary containment. The main steam nozzles on the RPV are evaluated with the reactor pressure vessel (Section 2.3.1.1).

The components for the MST System are located in the Turbine Building and Reactor Building steam chase. The MST System is normally operating continuously during normal plant operation for power generation.

The in-scope portion of the MST System consists primarily of piping and valves including the associated instrumentation. The major components are the main steam lines downstream of the MSIVs, TSVs and the associated piping, valves, and instrumentation for those components supplied with main steam.

Boundary

The MST System boundaries are shown on the following SLRBDs:

SLR-36033
SLR-36034
SLR-36035
SLR-36035-2
SLR-36241
SLR-36249
SLR-36251
SLR-54817-4

The major difference between the initial LR MST System boundary and the MST System SLR boundary is that the equipment between the RPV up to and including the outboard MSIVs is now in scope of the RCPB and Connected Piping System (Section 2.3.1.3). This change removes initial LR boundary drawings LR 36241-1 and LR 36249-10 from the MST System scope.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) The NSR MSIV leakage to main condenser drain pathway is in-scope in accordance with 10 CFR 54.4(a)(2) for iodine plate-out during hypothetical design basis accidents.

(2) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function in accordance with 10 CFR 54.4(a)(2).

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Sections 6.3, 11.1, 14.7.2.4.3, and 14.7.3.2.2

Components Subject to AMR

Table 2.3.4-4 lists the MST System component types that require an AMR and their associated component intended functions.

Table 3.4.2-4 provides the results of the AMR.

Table 2.3.4-4
Main Steam System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Orifice	Holdup and Plateout
Piping, Piping Components	Holdup and Plateout Leakage Boundary
Strainer (Element)	Filter
Valve Body	Holdup and Plateout Leakage Boundary

2.3.4.5 Off-Gas

Description

The Off-Gas System includes the NSR functions to remove non condensable off-gases from the main condenser, recombine the radiolytic hydrogen and oxygen normally present in the off-gas, and provide sufficient off-gas holdup time to allow decay of the short-lived radioisotopes to minimize iodine and radioactive particle release to the atmosphere.

Boundary

The Off-Gas System boundaries are shown on the following SLRBDs:

SLR-36034
SLR-36035
SLR-36035-2
SLR-36159
SLR-36249
SLR-54817-4
SLR-54818-1
SLR-100320

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) The Off-Gas System is in scope for the (a)(2) intended function of “holdup and plateout” as a result of the implementation of AST methodology for the analysis of the control rod drop accident.

(2) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Sections 9.3, 11.3.2, and 14.7.1

Components Subject to AMR

Table 2.3.4-5 lists the Off-Gas System component types that require AMR and their associated component intended functions.

Table 3.4.2-5 provides the results of the AMR.

Table 2.3.4-5
Off-Gas System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Condenser) Shell Side Components	Holdup and Plateout
Heat Exchanger (Condenser) Tube Sheet	Holdup and Plateout
Heat Exchanger (Condenser) Tubes	Holdup and Plateout
Heat Exchanger (Drain Cooler) Shell Side Components	Holdup and Plateout
Heat Exchanger (Drain Cooler) Tube Side Components	Holdup and Plateout
Heat Exchanger (H_2O_2 Sample Coolers) Tubes	Holdup and Plateout
Heat Exchanger (Inter-Condenser) Shell Side Components	Holdup and Plateout
Heat Exchanger (Inter-Condenser) Tube Sheet	Holdup and Plateout
Heat Exchanger (Inter-Condenser) Tubes	Holdup and Plateout

Table 2.3.4-5
Off-Gas System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Heat Exchanger (Pre-Heater) Shell Side Components	Holdup and Plateout
Heat Exchanger (Pre-Heater) Tube Side Components	Holdup and Plateout
Piping, Piping Components	Holdup and Plateout Leakage Boundary
Tanks (Condensate Flash Tank)	Holdup and Plateout
Tanks (Recombiner)	Holdup and Plateout
Valve Body	Holdup and Plateout Leakage Boundary

2.3.4.6 Turbine Generator

Description

The TGS System includes the turbine generator unit and the required subsystems as follows:

- Steam Sealing subsystem
- Turbine Lubricating Oil subsystem
- Hydrogen Cooling subsystem
- Hydrogen Seal Oil subsystem
- Stator Cooling subsystem

The function of the turbine is to convert the thermodynamic energy of the steam from the nuclear reactor into mechanical energy that drives the generator. The generator in turn converts that energy to an electrical energy that is sent to the power grid.

The turbine consists of one single flow high-pressure section with two double-flow low-pressure sections of the non-reheat design on a single shaft. The generator consists of three major parts; the rotor, stator, and exciter. The rotor is turned by the turbine shaft and is the source of the moving magnetic field. The stator consists of windings which form a conductive path for the current induced by the rotating magnetic field of the rotor. The exciter is a separate and smaller generator driven by the turbine to provide power for the main generator rotor magnetic field.

Steam Sealing subsystem

Turbine shaft seals are provided at each point where the shaft passes through the turbine casings. The Steam Sealing subsystem prevents steam leakage past the turbine shaft seals into the Turbine Building and limits air in-leakage to the turbine casings. During normal operation, steam from the high-pressure turbine seal leak-offs and from valve stem leak-offs supplies the low-pressure turbine seals. During startup, a regulated main steam supply furnishes sealing steam to all steam seals. An outer annulus of each shaft seal is connected to the steam packing exhauster. The steam packing exhauster maintains a slight negative pressure on the annulus to collect both air and steam that pass through the shaft seals. The collected gases are condensed and discharged to the condensate drip tank and the non-condensables are discharged to the off-gas holdup and recombiner system.

Turbine Lubricating Oil Subsystem

The turbine generator shaft is supported by 10 journal bearings. All bearing oil is supplied by the turbine lubricating oil subsystem, which also provides high-pressure oil to the hydraulic turbine control mechanisms. During normal operation, a shaft driven oil pump supplies the required oil. The subsystem includes a series of backup motor driven pumps. Prior to startup and for some time after shutdown the turbine generator unit will be on the turning gear, with the rotors being turned slowly to maintain uniform temperatures and prevent shaft bowing. During this time, shaft lift pumps discharge high pressure oil to each bearing assuring that the shaft is suspended and floating above the bearing surfaces.

Hydrogen Cooling subsystem

The hydrogen gas of the Hydrogen Cooling subsystem is contained within the generator casing. The Hydrogen Cooling subsystem is designed to reduce the heat generated from windage resistance and provide a good heat transfer medium for generator cooling. A fan blade on either end of the rotor circulates the hydrogen gas over the rotor and stator windings to remove heat. Four vertical tube-type heat exchangers are mounted in the casing to transfer the heat from the hydrogen gas to the Service Water System.

Hydrogen Seal Oil subsystem

The Hydrogen Seal Oil subsystem supplies vacuum treated oil between the rotor shaft and the generator end housing hydrogen seals to prevent hydrogen from escaping into the Turbine Building. Vacuum treated seal oil is supplied by a combination of components including a vacuum storage tank, a main and emergency seal oil pump, and a recirculation pump and spray header.

Stator Cooling Subsystem

The Stator Cooling subsystem removes heat from the generator stator by circulating low conductivity water through the hollow metal bars forming the stator windings. The subsystem also supplies cooling water to the generator exciter rectifier banks. The Stator Cooling subsystem consists of a storage tank feeding two parallel pumps, two heat exchangers, a filter, and connecting piping with the generator stator. A deionization loop through a resin bed provides for continuous purification of a portion of the stator cooling water. Stator cooling water flows through the shell side of the heat exchangers, with service water flowing through the heat exchanger tube side to provide two-pass cooling.

The in-scope portion of the TGS System consists of the high-pressure turbine casing, steam piping between the high-pressure turbine and the low-pressure turbines, moisture separators, moisture separator drain tanks, extraction steam piping supplying the CFW System feedwater heaters, and associated valves and instrumentation. The low-pressure turbine exhaust hoods are in scope for SLR and are evaluated in the CDR System (Section 2.3.4.3). In addition, components in the in-scope subsystems discussed above are located in the Turbine Building.

The portions of the TGS System containing components subject to an AMR include the closure bolting, heat exchangers, piping and piping components, pump casings, piping, tanks, turbine casings, valves, and other leakage boundary components within the Turbine Building.

Boundary

The TGS System boundaries are shown on the following SLRBDs:

SLR-8435-35-1
SLR-36033
SLR-36034
SLR-36035
SLR-36037
SLR-36041
SLR-36050
SLR-36052
SLR-M8107L-087

The major difference between the initial LR TGS boundary and the SLR TGS boundary is that the equipment originally identified with a component intended function of pressure boundary is now in scope with a function of leakage boundary.

This system also contains equipment not originally included in the initial LRA, such as the steam packing exhauster and its associated piping and equipment because this equipment supports the AST function; therefore, this equipment is in-scope with an intended function of holdup and plateout.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Post-accident containment holdup and plateout of MSIV bypass leakage. The TGS contains leakage from MSIVs and routes the leakage to the main condenser for holdup and plateout prior to release following LOCA.

(2) Maintain integrity of NSR components such that no interaction with SR components could prevent satisfactory accomplishment of a safety function in accordance with 10 CFR 54.4(a)(2).

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Section 11.2

Components Subject to AMR

Table 2.3.4-6 lists the TGS System component types that require an AMR and their associated component intended functions.

Table 3.4.2-6 provides the results of the AMR.

Table 2.3.4-6
Turbine Generator System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bolting (Closure)	Mechanical Closure
Heat Exchanger (Exciter Air Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger (Exciter Air Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger (Generator Hydrogen Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger (Generator Hydrogen Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger (Isophase Bus Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger (Isophase Bus Cooler) Tube Side Components	Leakage Boundary
Heat Exchanger (Stator Water Cooling Heat Exchanger) Shell Side Components	Leakage Boundary
Heat Exchanger (Stator Water Cooling Heat Exchanger) Tube Side Components	Leakage Boundary
Heat Exchanger (Steam Packing Exhauster) Shell Side Components	Holdup and Plateout
Heat Exchanger (Steam Packing Exhauster) Tube Side Components	Holdup and Plateout
Heat Exchanger (Turbine Lubricating Oil Cooler) Shell Side Components	Leakage Boundary
Heat Exchanger (Turbine Lubricating Oil Cooler) Tube Side Components	Leakage Boundary
Piping Elements	Leakage Boundary
Piping, Piping Components	Holdup and Plateout Leakage Boundary
Pump Casing (Emergency Bearing Oil Pump)	Leakage Boundary
Pump Casing (Emergency H2 Seal Oil Pump)	Leakage Boundary
Pump Casing (EPR Oil Pump)	Leakage Boundary
Pump Casing (Main H2 Seal Oil Pump)	Leakage Boundary
Pump Casing (Recirc H2 Seal Oil Pump)	Leakage Boundary

Table 2.3.4-6
Turbine Generator System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Pump Casing (Seal Oil Vacuum Pump)	Leakage Boundary
Pump Casing (Stator Liquid Cooling Pump)	Leakage Boundary
Pump Casing (Steam Packing Exhauster Blower)	Holdup and Plateout
Pump Casing (Turb Aux Oil Pump)	Leakage Boundary
Pump Casing (Turbine Lubricating Oil Purifier Pump)	Leakage Boundary
Pump Casing (Turbine Bearing Lift Pump)	Leakage Boundary
Pump Casing (Turning Gear Oil Pump)	Leakage Boundary
Tanks (Clean Lubricating Oil Storage Tank)	Leakage Boundary
Tanks (Dirty Lubricating Oil Storage Tank)	Leakage Boundary
Tanks (LO Purifier Tank)	Leakage Boundary
Tanks (Lubricating Oil Dump Overflow Tank)	Leakage Boundary
Tanks (Lubricating Oil Tank)	Leakage Boundary
Tanks (Moisture Separator Drain Tank)	Leakage Boundary
Tanks (Moisture Separator)	Leakage Boundary
Tanks (Oily Water Separator Tank)	Leakage Boundary
Tanks (Seal Oil Detraining Tank)	Leakage Boundary
Tanks (Stator Cooling Surge Tank)	Leakage Boundary
Tanks (Turbine Lubricating Oil Purifier Drain Tank)	Leakage Boundary
Turbine Casings (H.P. Turbine)	Leakage Boundary
Valve Body	Holdup and Plateout Leakage Boundary

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

2.4.1 Primary Containment

Description

The Primary Containment (PCT) consists of a drywell, which encloses the reactor vessel and recirculation pumps, a pressure suppression chamber (torus) which stores a large volume of water, a connecting vent system between the drywell and the suppression chamber, and isolation valves.

A detailed description of the principal components of the PCT System is provided below:

Drywell

The drywell is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion. It is enclosed in reinforced concrete (sacrificial shield) for shielding and to provide additional resistance to deformation and buckling over areas where the concrete backs up the steel shell. Above the foundation transition zone, the drywell is separated from the reinforced concrete by a gap of approximately 2 inches to allow for thermal expansion. Shielding over the top of the drywell is provided by a removable, segmented, reinforced concrete shield plug. The drywell vessel is provided with a removable hemispherical head to facilitate refueling. The head is held in place by bolts and sealed with a double gasket arrangement. The head is also provided with a 24-inch double-gasketed hatch. The hatch may be removed for inspection of the area under the head.

In addition to the drywell head with its bolted manway and one double door personnel airlock, two hatches (one large equipment hatch and one control rod drive hatch) are provided for access to the drywell. The equipment hatch is provided with a 10-foot diameter hatch cover and shielded with a removable concrete plug.

A seal plate and bellows assembly (RPV to drywell refueling seal) separates the drywell head volume from the lower volume. The seal plate is attached to the drywell shell. The stainless steel bellows attaches to the seal plate and the reactor vessel and allows for differential vertical movement between the drywell and reactor. This assembly serves as a watertight barrier during refueling operations. Potential leakage of water past the RPV to drywell refueling seal can only occur when the reactor is in cold shutdown with the reactor cavity flooded to support refueling operations.

The drywell is designed as a free standing shell supported by a concrete pedestal. It is, however, attached to the upper part of the biological shield by lateral struts that are intended to limit seismically induced lateral displacements of the reactor pressure vessel. The struts are attached to the drywell shell at the locations of the external seismic restraints. These restraints, which are spaced at 90° intervals, consist of mating steel pieces connected to the drywell exterior and to the sacrificial shield. The mating pieces allow vertical and radial growth of the drywell but restrict seismically induced lateral displacements to very small amounts.

There are several steel platforms in the drywell; these provide both personnel access and equipment support. The radial beams under the platforms are supported at the inner end by the vessel pedestal or biological shield and at the outer end by brackets attached to the drywell shell. The outer ends of the radial beams slide on Lubrite® plate assemblies; this allows unrestrained differential expansion between the platform supporting steel and the drywell shell.

During erection, the drywell was supported on two concentric steel skirts that anchor into the Reactor Building basemat. The inner skirt is effectively continuous up to the reactor vessel, to which it is joined. After the drywell was completed, these skirts were completely encased in a concrete pedestal that contacts about 40 percent of the projected drywell plan area. The inner skirt continues to anchor the drywell and reactor vessel against vertical motion relative to the reactor building, but the concrete provides essentially all vertical support. The outer skirt was not intended to serve a function after the pedestal concrete was in place. In fact, the design provided for cutting of the outer skirt along its circumference during concreting operations.

There is an annular sand pocket at the edge of the pedestal. The sand provides a transition to reduce the high moments and shears that would otherwise develop in the drywell wall at the edge of the pedestal.

A concrete equipment foundation mat covers the inside of the drywell over about 50 percent of the projected plan area. The top of the mat and the top of the sand pocket are at effectively the same level (920.5 ft. above plant datum). The mat supports the reactor pedestal as well as piping and equipment. The pedestal, in turn, supports the biological shield, piping, equipment and interior platforms. The reactor vessel itself is supported by the steel skirt at the inside face of the pedestal.

The reactor pedestal is concrete with a ¼-inch steel liner on the exterior face. The reactor support skirt is bonded to the inside face. A 3-inch layer of pneumatically applied concrete mortar with reinforcing mesh covers the inside face of the skirt. The biological shield consists of twelve 27 WF 177 columns with concrete fill to provide shielding. Steel liners (¼-inch or 1½-inch depending on location) cover both faces of the concrete.

There are numerous steel structures in the drywell including platforms and piping/equipment supports. These steel structures are supported by the drywell wall, the equipment mat, and the pedestal/biological shield.

The exterior of the drywell above the sand pocket is surrounded by a thick concrete structure, the sacrificial shield, that provides both radiological shielding and support for reactor building interior floors. A common pedestal supports both the drywell and the sacrificial shield. Both the sacrificial shield and the pedestal are a part of the Reactor Building and are covered in the AMR for that structure.

Personnel Airlock

The personnel airlock provides an entrance to the drywell measuring 6 feet by 2.5 feet. The locking mechanism on each manually operated airlock door is designed so a door may be operated only if the other door is closed and latched with the equalizing valve shut. A mechanical interlock accomplishes this.

Hand wheels are provided on the drywell side, the reactor building side, and in the interior of the airlock to open or close either door.

Suppression Chamber (Torus)

The suppression chamber is a steel pressure vessel in the shape of a torus located below and encircling the drywell. The suppression chamber is constructed of 16 mitered cylindrical shell segments. The suppression chamber is supported vertically at each milter joint location by inside and outside columns and by a saddle support located between the inside and outside columns. The integral support system of the torus takes vertical loads acting on the torus shell and transfers them to the Reactor Building basemat.

The suppression chamber is connected to the drywell by eight vent lines. Within the suppression chamber, the vent lines are connected to a common vent header. Connected to the vent header are 48 pairs of downcomers which terminate below the water level of the suppression pool. The vent lines include jet deflectors which span the openings of the vent lines. A bellows assembly connecting the suppression chamber to the vent line allows for differential movement between the drywell and the suppression chamber. The vent system is supported vertically by two column members at each miter joint location. The columns are pinned top and bottom to accommodate the differential horizontal movement between the vent header and the suppression chamber.

Access from the Reactor Building to the torus is provided through two manholes with double-gasketed, bolted covers. These access ports are bolted closed when primary containment integrity is required.

Containment Penetrations

<u>Piping Penetrations</u>

Pipe penetrations are of two general types: those that accommodate thermal movement (hot), and those that experience relatively little thermal movement (cold).

Fluid piping penetrations for which movement provisions are made are high temperature lines such as the main steam line and certain other reactor auxiliary and cooling system lines. These penetrations have a guard pipe between the hot line and the penetration nozzle in addition to a double-seal arrangement. This permits the penetration to be vented to the drywell should a rupture of the hot line occur within the penetration. The guard pipes are designed to the same pressure and temperature as the fluid line and are attached to a penetration head fitting, a one-piece forging with integral flues or nozzles. These were designed to the ASME, Section III, Class B. The penetration sleeve is welded to the drywell and extends through the biological shield where it is welded to a bellows which in turn is welded to the guard pipe. The bellows accommodates the thermal expansion of the drywell. A double bellows arrangement permits leak testing of the penetration seal. The lines are constrained to limit the movement of the line relative to the containment yet permit pipe movement parallel to the penetration.

Small bore lines which connect to high-pressure systems, such as instrument lines and control rod drive hydraulic lines, do not have a double-seal penetration sleeve. These lines are either bunched in groups of six lines and welded in a single pipe sleeve or shop welded in large groups directly to the drywell plate. The mechanical problems involved with this number of small penetrations in a relatively small area make it impractical to provide individual penetration sleeves. The pipes are designed to deflect with the drywell shell.

Cold piping penetration pipe sleeves which attach to the drywell are designed for 62 psig, but because of structural thickness, can withstand a substantially higher pressure. No bellows are required since thermal expansion is minimal.

All pipes that penetrate the Primary Containment are welded to a containment sleeve with the sleeve welded to the containment shell. There is no direct weldment of the pipe to the containment shell.

Electrical Penetrations

Electrical penetration seals were designed to accommodate the electrical requirements of the plant. These are functionally grouped into low voltage power and control cable penetration assemblies, high voltage power cable penetration assemblies, and shielded cable penetration assemblies. All canister type electrical penetration seals have essentially the same basic configuration. The assemblies are sized to be inserted in the 12-inch schedule 80 penetration nozzles which are furnished as part of the containment structure.

On canister type penetrations, header plates conforming to the inner diameter of the penetration nozzle are provided at each end of the penetration assembly, forming a double pressure barrier. On modular type penetration X-101a, double electric conductor seals and a single aperture seal are provided. Double aperture seal is provided by a leak-chase-channel that monitors the Electrical Penetration Assemblies (EPA)/nozzle weld. Radiation shielding is attached to many of the penetrations on the drywell side to provide external access to the electrical connections during plant operation.

Boundary

The PCT System boundaries are shown on the following SLRBD:

SLR-36444.

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provide a barrier, which, in the event of a LOCA, controls the release of fission products to the secondary containment and the environment and rapidly reduces the pressure in the containment resulting from a LOCA.

(2) Provide shelter/protection to SR components and provide a missile barrier to turbine-and tornado-generated missiles.

(3) Provide a source of cooling water to maintain the reactor in a safe condition following a DBA or LOCA.

(4) Provide structural support to SR components.

(5) Provide a water seal for piping penetrations that terminate beneath the minimum water level of the suppression chamber.

(6) Provide penetration assemblies that maintain leak-tight integrity but allow process piping and instrumentation, electrical power and control cabling, and a personnel and equipment hatch to penetrate/enter and leave containment.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Contains NSR SSCs which could potentially affect the satisfactory accomplishment of SR functions.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Contains structures and/or components which perform a function that demonstrates compliance with the Commission's regulations for FP, ATWS, and SBO.

<u>USAR References</u>

Sections 1.3.3.1, 3.1.3, 5.1, 5.2.2.2, 5.2.2.3, 5.2.2.4.1, 5.2.2.4.2, 5.2.2.5.2, and 12.2.2.1.1

Table 5.2-3a

<u>Components Subject to AMR</u>

Table 2.4-1 lists the PCT structure and internal structural component types that require an AMR and their associated component intended functions.

Table 3.5.2-1 provides the results of the AMR.

Table 2.4-1
Primary Containment Structure and Internal Structural Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Biological Shield Wall	Radiation Shielding Structural Support
Biological Shield Wall (Columns, beams liner, doors)	Structural Support
Bolting (Containment Closure)	Pressure Boundary Structural Support
Bolting (Structural)	Structural Support
Concrete: Interior (Drywell Equipment Foundation, RPV Pedestal)	Structural Support

Table 2.4-1
Primary Containment Structure and Internal Structural Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Downcomers	Direct Flow Pressure Boundary Structural Support
Drywell Shell; Drywell Head; Drywell Shell in Sand Pocket Regions	HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support
Drywell Support Skirt, Embedded Shell	Structural Support
ECCS Suction Header	Emergency Cooling Water Source Pressure Boundary
Liner, Liner Anchors, Integral Attachments (RPV Pedestal)	Structural Support
Moisture Barrier	Shelter/Protection
Penetration Assemblies - Electrical	Flood Barrier HELB Barrier Pressure Boundary Shelter, Protection Structural Support
Penetration Assemblies - Mechanical (Bellows)	Flood Barrier HELB Barrier Pressure Boundary Structural Support
Penetration Assemblies - Mechanical (Sleeves)	Flood Barrier HELB Barrier Pressure Boundary Shelter, Protection Structural Support
Penetration Assemblies - Mechanical Piping (Adapters)	Flood Barrier HELB Barrier Pressure Boundary Shelter, Protection Structural Support
Penetration Assemblies - Mechanical Piping (Torus Penetrations, Drywell Penetration Bellows)	Flood Barrier HELB Barrier Pressure Boundary Shelter, Protection Structural Support
Personnel Airlock, Equipment Hatch, CRD Hatch (Including Locks, Hinges, and Closure Mechanisms), Seismic Restraint Inspection Ports	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary
RPV to Drywell Refueling Seal	Structural Support Watertight Seal

Table 2.4-1
Primary Containment Structure and Internal Structural Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Seals and Gaskets	HELB Barrier Pressure Boundary
Service Level I Coatings	Maintain Adhesion
Sliding Surfaces (Drywell Interior Platform Sliding Plates)	Structural Support
Structural Steel (Torus Internal Catwalks Support Columns)	Structural Support
Structural Steel (Torus Internal and External Catwalks, Drywell Interior Platforms, Stabilizers, Radial Beam Seats, etc.)	Structural Support
Thermowells	Flood Barrier Pressure Boundary Structural Support
Torus Shell	Emergency Cooling Water Source Flood Barrier Heat Sink HELB Barrier Missile Barrier Pressure Boundary Structural Support
Torus Shell, Ring Girders	Emergency Cooling Water Source Flood Barrier Heat Sink HELB Barrier Missile Barrier Pressure Boundary Structural Support
Torus, Vent Lines, Vent Header	Emergency Cooling Water Source Direct Flow Flood Barrier Heat Sink HELB Barrier Missile Barrier Pressure Boundary Structural Support
Vent Line Bellows	Flood Barrier Pressure Boundary Structural Support
Vent Line Jet Deflectors	Shelter, Protection HELB Barrier

2.4.2 Cranes, Heavy Loads, Rigging

Description

The Cranes, Heavy Loads, Rigging System consists of the Reactor Building and Turbine Building cranes, numerous hoists, lifting fixtures and devices, and other miscellaneous smaller cranes. Also included in this system are the reactor components handling equipment such as the refueling bridge, controls, lifting devices and fixtures. These cranes and lifting devices were identified to have the potential for a heavy load drop, which could result in damage to safe shutdown equipment. The remainder of the cranes, hoists, and lifting devices are excluded due to their load carrying capacity (being less than that of a heavy load) or their lack of proximity to safe shutdown equipment. The refueling rod block interlocks are included under the Reactor Manual Control (RMC) System.

Boundary

The boundary for the Cranes, Heavy Loads, Rigging System is the load handling components that comply with NUREG-0612 and large fueling handling equipment normally stored above or in the fuel pool. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The Cranes, Heavy Loads, Rigging System boundaries are shown on the following SLRBD:

SLR-36444

Commodity Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) By definition of NUREG 0612, the safe handling of heavy loads is a nonsafety affecting safety function or the load handing systems are required to meet single failure proof criteria.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None.

USAR References

Section 12.2.5

Components Subject to AMR

Table 2.4-2 lists the Cranes, Heavy Loads, Rigging System component types that require AMR and their associated component intended functions.

Table 3.5.2-2 provides the results of the AMR.

Table 2.4-2
Cranes, Heavy Loads, and Rigging System Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Cranes and Lifting Devices	Structural Support
Fuel Prep Machine Framing	Structural Support
Refueling Platform	Structural Support
Structural Bolting	Structural Support

2.4.3 Diesel Fuel Oil Transfer House

Description

The Diesel Fuel Oil Transfer House, located north of the Diesel Generator Building and west of the INS, is a reinforced concrete, mat foundation building that provides protective enclosure for the DOL transfer pumps. It is a Class 2 structure analyzed to Class 1 requirements as described in Section 12.2.1.2 of the USAR.

The structure is rectangular with external dimensions of 11-ft 6-in (N-S) x 14-ft (E-W) x 13-ft 6-in high. Walls are 1-ft 6-in thick. The floor slab (mat) and roof (placed on corrugated steel decking) are 1-ft thick. There is a personnel access door at the north end of the east wall and a 3-ft 9-in x 2-ft 9-in equipment access hatch in the southeast corner of the roof. An interior wall, 1-ft 6-in thick, located opposite the door serves as a missile barrier. The missile barrier is 3-ft in from the east wall and extends 6-ft south from the north wall. One wide flange beam, extending from the missile barrier to the west wall, supports the west side of the roof slab. A light structural member, attached to the beam and the south wall, serves as a suspension point for a chain or cable hoist.

The top of the floor slab is at EL. 926-ft, 3-ft -6-in below the EL. 929-ft 6-in nominal grade level at the transfer house location. The door sill is at EL. 930-ft. A steel staircase between the east wall and the missile barrier provides access down to the floor slab. There is a 1-ft 6-in square x 1-ft deep sump along at the center of the west wall. The diesel oil transfer pumps are in the open area west of the missile barrier. The two transfer pumps are mounted on concrete pedestals doweled into the floor slab.

Embeds are cast into the east and south walls. Nothing is attached to these. Drilled in anchor bolts support all items that are mounted on the walls.

The mat foundation (floor slab) rests on compacted granular material.

Boundary

The boundary for the Diesel Fuel Oil Transfer House encompasses the transfer house structure itself (foundation, framing, walls, floors, roof), various interior structural assemblies, doors, and equipment support pedestals. Mechanical systems, electrical equipment, component supports and associated commodities inside the transfer house are covered in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The Diesel Fuel Oil Transfer House boundaries are shown on the following SLRBD:

SLR-36444

Structure Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Supports and protects the Diesel System transfer pumps.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Contains NSR platforms, stairs etc., the failure of which may affect SR components.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Supports essential FP equipment (the transfer pumps supply fuel oil to the diesel fire pump day tank).

USAR References

Section 12.2.1.2

Components Subject to AMR

Table 2.4-3 lists the Diesel Fuel Oil Transfer House component types that require AMR and their associated component intended functions.

Table 3.5.2-3 provides the results of the AMR.

Table 2.4-3
Diesel Fuel Oil Transfer House Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support

Table 2.4-3
Diesel Fuel Oil Transfer House Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Interior Walls, Ceilings, and Floors	Missile Barrier Shelter, Protection Structural Support
Doors	Flood Barrier Shelter, Protection
Miscellaneous Structural Components	Structural Support Missile Barrier
Structural Bolting	Structural Support

2.4.4 Emergency Diesel Generator Building

Description

The Emergency Diesel Generator Building (DGB) is primarily a concrete and steel framed Class 1 structure that provides a protective enclosure for the EDGs and the generator auxiliaries. A partial second story extends over a portion of the structure.

Vent paths, ventilation openings and portions of the standby diesel generators (intake and exhaust piping) that extend to beyond the reinforced concrete structure are enclosed or protected by several secondary steel structures of the building.

Ground floor is at EL. 931-ft and consists of a concrete slab which is independent of the building structure and placed on compacted select fill. Exterior walls are of reinforced concrete and support the lower roof and second story framing at EL. 950-ft and EL. 949-ft, respectively. The second story roof framing is at EL. 959-ft 6-in. The roof over the single-story portion of the structure and over the penthouse consists of a thick reinforced concrete slab supported by structural steel framing. A north-south interior wall of reinforced concrete extends the full height of the structure providing physical separation of the diesel generator systems. The exterior and interior walls extend six feet below grade to form a continuous wall footing supported on select fill.

The EDGs are located at grade and are supported on a three-foot-thick reinforced concrete mat which is physically independent of the ground floor slab and building structure. Information on the DGB is found in Section 12.2.2.4 of the USAR.

Boundary

The boundary for the DGB encompasses the DGB structure itself (foundation, framing, walls, floors, roof), various interior structural assemblies, doors, and equipment support pedestals. Mechanical systems, electrical equipment, component supports and associated commodities inside the DGB are covered in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The DGB boundaries are shown on the following SLRBD:

SLR-36444

Structure Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Supports and protects SR components.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Supports and protects Category (1) systems, structures, & components.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Protects enclosed structures, components and commodities from external fires as well as supports enclosed FP equipment.

USAR References

Section 12.2.2.4

Components Subject to AMR

Table 2.4-4 lists the DGB component types that require AMR and their associated component intended functions.

Table 3.5.2-4 provides the results of the AMR.

Table 2.4-4
Emergency Diesel Generator Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Concrete: Interior Walls, Ceilings, and Roof	Missile Barrier Shelter, Protection Structural Support
Doors	Shelter, Protection
Joint and Penetration Seals	Flood Barrier Shelter, Protection
Masonry (Block) Walls	Flood Barrier Shelter, Protection Structural Support

Table 2.4-4
Emergency Diesel Generator Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Miscellaneous Structural Components	Missile Barrier Structural Support
Structural Bolting	Structural Support

2.4.5 Emergency Filtration Train Building

<u>Description</u>

The EFB is an L-shaped reinforced concrete structure. The east section has approximate plan dimensions of 46-ft (N-S) x 28-ft 8-in feet (E-W). The east section is three stories high, and the west section is two stories high. The duct bank riser on the outside of the east wall is included as part of the EFB.

The east section of the EFB is supported by a mat foundation. The bottom of the mat is 2-ft 5-in below grade (nominally EL. 931-ft). The mat is supported on a compact granular soil consisting of fine to coarse sand. The west section of the EFB is supported by a reinforced concrete beam resting on two reinforced concrete caissons. Information on the EFB is found in Section 12.2.2.14 of the USAR.

<u>Boundary</u>

The boundary for the EFB encompasses the EFB structure itself (foundation, framing, walls, floors, roof), various interior structural assemblies, doors, seals, and equipment support pedestals. Mechanical systems, electrical equipment, component supports and associated commodities inside the EFB are covered in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The EFB boundaries are shown on the following SLRBD:

SLR-36444

<u>Structure Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

(1) Provides safe enclosure and protection for the main components of the MCR air conditioning system (including the emergency filtration train units for the MCR air conditioning system) and provide an environmental boundary for the CRV-EFT System. The EFB is credited in the ATWS, SBO and the FP regulated events.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Supports and protects protecting Category (1) systems, structures, & components.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Supports SSCs considered in-scope due to FP, SBO and ATWS.

USAR References

Section 12.2.2.14

Components Subject to AMR

Table 2.4-5 lists the EFB component types that require AMR and their associated component intended functions.

Table 3.5.2-5 provides the results of the AMR.

Table 2.4-5
Emergency Filtration Train Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Concrete: Interior Walls, Ceilings, and Roof	Missile Barrier Shelter, Protection Structural Support
Doors	Shelter, Protection
Joint and Penetration Seals	Shelter, Protection
Miscellaneous Structural Components	Missile Barrier Structural Support
Structural Bolting	Structural Support

2.4.6 Fire Protection Barriers Commodity Group

Description

The Fire Protection Barriers Commodity Group includes fire stop sealants, fireproofing, and metallics such as aluminum and carbon steel credited in the Fire Protection (B.2.3.15) Program. Fire stop sealants, fireproofing, and metallics can be used as FP barriers to stop the spread of fire to adjacent fire areas and can also be used to encapsulate structural steel or other metallic and non-metallic components located within a fire area to protect them from the effects of a fire.

Fire stop sealants, fireproofing, metallics, and combinations thereof prevent the spreading of fire to adjacent fire areas. Fire stop sealants, fireproofing, and metallics are used to close openings in ceilings, floors, and walls. These openings may be for penetrating electrical (e.g., cables, cable trays, conduits) or mechanical components (e.g., pipes, instrument lines, ventilation duct).

Ventilation duct fire barrier housings, located between adjacent fire areas, are an integral part of the FP barrier and are therefore included with the Fire Protection Barriers Commodity Group.

The portions of the Fire Protection Barriers Commodity Group include cable tray covers, FP guard pipe, fire damper housing, fire stop sealants (silicone, silicone foam, caulk), and cementitious (Pyrocrete walls, etc.), thermal fiber (silicates), and rigid board (gypsum walls, etc.) fireproofing.

Fire doors, structural fire barriers, and masonry block walls that are fire barriers are evaluated as part of the Fire Protection Barriers Commodity Group for SLR.

Curbs, dikes, concrete components other than barriers are evaluated as part of the structure where they are located. Fire detection and alarm system (e.g., smoke detectors), and fire suppression (e.g., automatic sprinklers, automatic halon systems) are evaluated in the FIR System (Section 2.3.3.9). The diesel-driven fire pump is evaluated in the FIR System (Section 2.3.3.9). Information on the Fire Protection Barriers Commodity Group is found in Section 10.3 and Appendix J of the USAR.

Boundary

The boundary for the Fire Protection Barriers Commodity Group includes fire stop sealants, fireproofing, and metallics such as aluminum and carbon steel credited in the Fire Protection (B.2.3.15) Program. In addition, for SLR, fire doors and structural fire barriers were evaluated as part of the Fire Protection Barriers Commodity Group rather than with the individual structures where they were located.

The Fire Protection Barriers Commodity Group boundaries are located in structures shown on the following SLRBD:

SLR-36444

Commodity Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Supports and protects Category (1) systems, structures, & components.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Supports SSCs considered in-scope due to fire protection.

USAR References

Section 10.3
Appendix J

Components Subject to AMR

Table 2.4-6 lists the Fire Protection Barriers Commodity Group component types that require AMR and their associated component intended functions.

Table 3.5.2-6 provides the results of the AMR.

Table 2.4-6
Fire Protection Barriers Commodity Group Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Cable Tray Cover	Fire Barrier
Fire Barrier Penetration Seals	Fire Barrier
Fire Damper Housing	Fire Barrier
Fire Rated Doors	Fire Barrier
Fireproofing	Fire Barrier
Masonry (Block) Walls	Fire Barrier
Non-metallic Fireproofing	Fire Barrier
Structural Fire Barriers (Walls, Ceilings and Floors)	Fire Barrier
Thermal fiber	Fire Barrier

2.4.7 Hangers and Supports Commodity Group

Description

The Hangers and Supports Commodity Group contains component and equipment supports, pipe restraints, junction boxes, control panels (considered supports), electrical raceways, and electrical conduits associated with plant systems and equipment that are in scope for LR or are located within structures containing SR components. This commodity group includes the grout under the baseplate and fasteners used with the support or equipment anchorage.

Generally, hangers and supports provide the connection between a system's equipment or component and a plant structural member (e.g., wall, floor, ceiling, column, beam). They provide support for distributed loads (e.g., piping, tubing, HVAC ducting, conduit, cable trays) and localized loads (e.g., individual equipment). Specific types of equipment and components evaluated as part of this commodity group include:

- Pipe Supports/Restraints - Includes all items used to support and/or restrain piping as well as jet impingement barriers (e.g., high energy line break barriers) and pipe whip restraints. The support boundary includes all the auxiliary steel back to the structure’s surface includes grout and anchor bolts. Integral welded attachments, i.e., lugs and stanchions, are considered with the piping system.

- Equipment Supports - Includes structural steel, fasteners (e.g., bolts, studs, nuts) and vibration mounts that secure equipment to structures.

- HVAC Duct Supports - Includes structural steel and fasteners (e.g., bolts, studs, nuts) that support/attach ventilation duct to structures.

- Raceways - Generic component type that is designed specifically for holding electrical wires and cables, such as cable trays, exposed and concealed metallic conduit, junction boxes or wireways. Commodity assets for raceways include both the component and the component's support and attachment.

- Electrical Enclosures - Generic component type that contains electrical components such as panels, junction boxes, cabinets, consoles, metal enclosed bus exteriors, and bus ducts. An electrical enclosure includes both the enclosure and its supports and attachments.

- Piping and component insulation/jacketing – Generic component type that includes anti-sweat and personnel protection insulation for mechanical piping and components.

The Hangers and Supports Commodity Group excludes masonry wall supports and miscellaneous plant structures (e.g., stairs, platforms, crane rails). These items were evaluated in this report as components in the structure where they are located. Sections 12.2.1.10.1 and 12.2.1.10.2 of the USAR provide further detail.

<u>Boundary</u>

The boundary for the Hangers and Supports Commodity Group includes component and equipment supports, pipe restraints, junction boxes, control panels (considered supports), electrical raceways and electrical conduit associated with plant systems and equipment that are in scope for LR or are located within structures containing SR components. This commodity group includes the grout under the baseplate and fasteners used with the support or equipment anchorage. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The Hangers and Supports Commodity Group boundaries are located in structures shown on the following SLRBD:

SLR-36444

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

(1) Supports and protects SR components.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Supports and protects NSR components whose failure could affect the capability of SR SSCs to perform their safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Supports SSCs considered in-scope due to FP, SBO and ATWS.

USAR References

Sections 12.2.1.9 and 12.2.1.10

Components Subject to AMR

Table 2.4-7 lists the Hangers and Supports Commodity Group component types that require AMR and their associated component intended functions.

Table 3.5.2-7 provides the results of the AMR.

Table 2.4-7
Hangers and Supports Commodity Group Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Anchorage / Embedment	Structural Support
ASME Class 1, 2, 3, and MC Supports	Structural Support
ASME Class 1, 2, 3, and MC Structural Bolting	Structural Support
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Component Supports	Structural Support
Concrete: Diesel Fuel Oil Storage Tank Deadmen	Structural Support
Electrical Enclosures	Shelter, Protection Structural Support
HVAC Duct Supports	Structural Support
Insulation	Insulation Jacket Integrity Thermal Insulation
Pipe Restraints	Pipe Whip Restraint Structural Support
Sliding Surfaces for ASME Class 1, 2, and 3 Piping and Components	Structural Support
Sliding Surfaces for Torus Saddles	Structural Support
Structural Bolting	Structural Support
Vibration Isolation Elements	Structural Support

2.4.8 High Pressure Coolant Injection Building

Description

The HPCI Building, which houses the HPCI turbine/pump set and supporting items, is an underground structure that extends out from the west side of the Reactor

Building and is adjacent to the south wall of the Turbine Building. It is structurally a part of the Reactor Building. The HPCI Building consists of a single room.

The building is principally a reinforced concrete structure with a mat foundation. Approximate dimensions are 57 feet by 31.5 feet and 47.75 feet high. The HPCI Building is closed on the east side by the west wall of the Reactor Building and on the other three sides by 3.5-foot thick concrete walls. The north wall is separated from the Turbine Building wall by a 1-inch seismic gap. The exterior surfaces of the basemat (except the north face), south wall, and west wall are in contact with backfill. The north wall and the north face of the basemat are in contact with the Turbine Building retaining wall up to EL. 902-ft 6-in. Above this level, the north wall is separated from the Turbine Building basemat and wall by a seismic gap.

The roof is a reinforced concrete slab. The top of the slab, which is exposed to the outside environment except where it is covered by the hydrogen storage building, slopes down to the west (away from the Reactor Building) for drainage. The west edge of the slab is at plant grade elevation (EL. 935-ft). There is an equipment access hatch, fitted with upper and lower concrete covers, in the southwest corner of the slab. Wide flange members provide additional support to the slab along the inside edges of the opening. Both the slab and the covers have angle reinforcements to prevent spalling at the exposed edges. These angles serve no structural or containment function. Descriptions of the HPCI Building are given in USAR Section 12.2.2.2.

Boundary

The boundary for the HPCI Building includes the building structure itself (foundation, walls, floors & roof), the hatch cover, piping penetration seal plates and various interior structural assemblies. The Reactor Building, which is monolithic with, and open to, the HPCI Building, is evaluated in Section 2.4.15; mechanical systems, electrical equipment, component supports and associated commodities inside the HPCI Building are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The HPCI Building boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Supports and protects SR components.

(2) Provides secondary containment, as well as primary containment during outages, and limiting offsite exposures to allowable levels. The HPCI Building performs this function in conjunction with the Standby Gas Treatment System, which processes contaminated air exhausted from the structure.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Supports and protects NSR components whose failure could affect the capability of SR SSCs to perform their safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Provides a protective enclosure for equipment required to support operations during the station blackout event (10 CFR 50.63).

USAR References

Sections 5.3 and 12.2.2.2

Components Subject to AMR

Table 2.4-8 lists the HPCI Building component types that require AMR and their associated component intended functions.

Table 3.5.2-8 provides the results of the AMR.

Table 2.4-8
HPCI Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Pressure Boundary Radiation Shielding Shelter, Protection Structural Support
Concrete: Interior Walls, Ceilings, and Roof	Pressure Boundary Shelter, Protection Structural Support
Joint and Penetration Seals	Shelter, Protection
Miscellaneous Structural Components	Structural Support
Piping Penetration Seal Plates	Flood Barrier Pressure Boundary Shelter, Protection
Platforms	Structural Support
Structural Bolting	Structural Support

2.4.9 Intake Structure

Description

The INS is a Class 2 facility that serves as the source of river water for plant cooling and FP systems. It consists of an inlet channel open to the river, an uncovered, reinforced concrete forebay and a reinforced concrete chambered structure that encloses traveling screens (screen drives are in a separate building constructed on the intake roof), various pumps and water passages. The intake houses certain SR pumps and was, therefore, analyzed as required for a Class 2 structure housing Class 1 equipment. It is oriented N-S; the riverbank at the intake location runs approximately E-W.

The INS is basically a chambered box of reinforced concrete construction. It consists of four 13.7-ft bays with an invert elevation of 888-ft at the intake end which converges to a two-section suction chamber at the discharge end. A circulating water pump is mounted over each suction chamber. The roof of the structure is approximately 4.25 feet above grade at the 934-ft 3-in elevation and consists of reinforced concrete beam and slab framing. An operating floor is located at the 919-ft elevation on which the ESW and RHRSW pumps are mounted. Exterior and interior walls and slabs are constructed of reinforced concrete and provide support for the operating floor and roof framing. The structure is supported on a mat foundation 3.5 feet thick that was placed on a lean concrete fill which overlays a layer of cemented sandstone.

In addition to the INS itself, this structure also covers the access tunnel and Diesel Fire Pump House.

The access tunnel is a reinforced concrete, below grade, N-S passageway between the north side of Turbine Building and east side of the intake. It provides personnel access to the intake pump room and also serves as a chase for piping, cable tray, & conduit.

The Diesel Fire Pump House is a small building situated on the northeast corner of the INS pump room roof. It provides a protective enclosure for the diesel fire pump.

The INS includes steel plates on top of the INS and connects to the bin walls adjacent to the INS that serve to provide protection for the site from flooding.

USAR Sections 12.2.2.7.1 and 12.2.2.7.2 provide descriptions of the intake and tunnel, respectively.

<u>Boundary</u>

The boundary for the INS includes the structure itself (including the forebay and inlet channel) and the access tunnel connecting this structure with the Turbine Building and the Diesel Fire Pump House. It also includes the primary structural elements (foundation, framing, walls, floors, roof) as well as doors, equipment support pedestals, embedments that transfer loads from component supports, and related passive items that perform a LR intended function. Mechanical systems, electrical equipment, component supports, and associated commodities inside these structures are covered in the AMRs applicable to those systems/commodities. The INS was modified subsequent to the initial MNGP LR to enhance the flood protection of the site by adding steel plates on top of the INS and adding bin walls adjacent to the intake. The steel plates and bin walls are within the scope of SLR.

The INS boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Supports and protects SR components.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Supports and protects (from external missiles, flooding, and the outside environment) the SR ESW pumps, RHRSW pumps and associated piping, wiring, & instrumentation.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Supports FP water pumps and associated piping, wiring & instrumentation.

USAR References

Sections 12.2.2.7.1 and 12.2.2.7.2

Components Subject to AMR

Table 2.4-9 lists the INS component types that require AMR and their associated component intended functions.

Table 3.5.2-9 provides the results of the AMR.

Table 2.4-9
Intake Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Bin Wall and Steel Plates	Flood Barrier
Concrete: Basemat, Foundation	Flood Barrier Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Concrete: Intake Structure and Access Tunnel Roof Slabs	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Doors, Ventilation Assemblies	Flood Barrier HELB Barrier Shelter, Protection Structural Support
Masonry (Block) Walls	Structural Support
Miscellaneous Structural Components	Flood Barrier Structural Support
Joint and Penetration Seals	Flood Barrier HELB Barrier

Table 2.4-9
Intake Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Sheet Piles	Structural Support
Stored Steel Plates, Hatch Covers and Bin Wall	Flood Barrier
Structural Bolting	Structural Support

2.4.10 Miscellaneous Station Blackout Yard Structures

Description

The miscellaneous SBO yard structures are those yard structures that provide support for equipment relied upon for recovery from a station blackout. These structures are listed below:

- The foundations and transformer structures for 1R, 2R, 1AR and 2RS Transformers
- The 115/345 kV Control House
- The towers/foundations for the 1N2, 1N6, 5N5, 5N7, 8N4, 8N7, 8N10, and 8N11 breakers
- The towers/foundations for the bus bars between the 2RS transformer and the 8N4, 8N7, 8N10, and 8N11 breakers, this includes the towers/foundations for the 3N4 breaker, 3N5 fused disconnect and the towers/foundations to the 1ARS motor operated disconnect (MOD).
- The towers/foundations for the bus bars for the 5N5 and 5N7 breakers. This includes the west four rows of columns and the beams that connect them together.
- The Trenwa trenches connecting the control house to the 115 kV ring bus.
- The Trenwa trenches connecting the control house to the 345 kV breaker-and-a-half bus.
- The electrical duct bank from the 1N2 breaker to the 1AR transformer.
- The tower/foundation for the 115 kV bus 1 potential transformer.
- The three 115 kV transmission towers along the west Owner Control Area (OCA) fence between the switchyard and the 1R transformer and the first transmission tower northwest of the plant.
- The block walls surrounding the 1R and 2R transformers.
- The foundation for the CST tanks.

This AMR covers the passive portions of the miscellaneous SBO yard structures that are considered a part of the various structures including concrete, masonry walls and carbon steel, low alloy steel components. Additional details of the miscellaneous SBO yard structures can be found in the USAR, Sections 12.2.1.2, 12.2.1.3, and 8.2.

Boundary

The boundary for the miscellaneous SBO yard structures includes those yard structures that provide support for equipment relied upon for recovery from a station blackout. This includes the passive portions that are considered a part of the various structures including concrete, masonry walls, carbon steel, and low alloy steel components. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The miscellaneous SBO yard structures boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

None

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Supports SSCs that provide functions relied upon for 10 CFR 50.63, station blackout.

USAR References

Sections 8.2, 12.2.1.2, and 12.2.1.3

Components Subject to AMR

Table 2.4-10 lists the miscellaneous SBO yard structures component types that require AMR and their associated component intended functions.

Table 3.5.2-10 provides the results of the AMR.

Table 2.4-10
Miscellaneous SBO Yard Structures Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: 345 kV House, Foundations, Trenches, and Duct Banks	Structural Support

Table 2.4-10
Miscellaneous SBO Yard Structures Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Masonry (Block) Walls	Structural Support
Miscellaneous Structural Components	Structural Support
Structural Bolting	Structural Support

2.4.11 Off-Gas Stack

Description

The off-gas stack is a free-standing tapered, reinforced concrete structure that encloses and supports an independent gas flue. The overall height of the stack above adjacent grade (nominally taken as EL 932-ft) is 328 feet. The internal diameter of the concrete shell is 7 feet at the top and 32 feet at the 946-ft 6-in elevation with thickness varying from 7 inches at the top to 10 inches at the 946-ft 6-in elevation. The top of the stack is covered with a funnel shaped stainless steel cap.

Below the 946-ft 6-in elevation to the top of the foundation pedestal at the 932-ft 6-in elevation, the stack shell is a polygon having a maximum inscribed diameter of 34 feet. The wall thickness varies in accordance with radiation shielding requirements.

The stack shell is supported on a 4-foot thick octagonal spread footing with a 1.5-ft pedestal. The independent gas flue is 18 inches in diameter reducing to 14 inches in diameter at the top.

The stack interior floors are concrete. The interior walls are constructed of either concrete or masonry block. The ceiling for the sample room on the 946-ft 6-in elevation is constructed of steel decking with insulation. In addition, the sample room interior walls are covered with insulation and gypsum board. More information on the off-gas stack is found in Section 12.2.2.6 of the USAR.

Boundary

The boundary for the off-gas stack includes the structure itself (foundation, walls, floors & roof) and various interior structural assemblies. Mechanical systems, electrical equipment, component supports and associated commodities inside the off-gas stack are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The off-gas stack boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides controlled release and dispersal of gaseous radioactive wastes, houses SR and NSR equipment, and provides radiation shielding.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Portions of the stack are NSR, platforms, stairs, ladders, etc., however, failure of these components may affect SR components.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None

USAR References

Section 12.2

Components Subject to AMR

Table 2.4-11 lists the off-gas stack component types that require AMR and their associated component intended functions.

Table 3.5.2-11 provides the results of the AMR.

Table 2.4-11
Off-Gas Stack Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Pedestal, Walls, Slabs	Flood barrier Shelter, protection Structural support
Doors	Flood barrier Shelter, Protection
Masonry (Block) Walls	Shielding Structural Support
Miscellaneous structural components	Flood Barrier Shelter, Protection Structural Support
Stainless Steel Cap	Shelter, Protection Structural Support
Structural Bolting	Structural Support

2.4.12 Off-Gas Storage and Compressor Building

Description

The Off-Gas Storage and Compressor Building (OGB) is a reinforced concrete structure located near the base of the off-gas stack. The main rooms in the building are the tank storage room, the valve room, the compressor room, the fan room, and the foyer.

The OGB is supported on a mat foundation at varying levels. The lowest level of the mat is at EL. 916-ft 2-in (room with tank V-811). The nominal grade around the OGB is at EL 932-ft. However, the ground around the OGB is sloped up from the nominal grade elevation of 932-ft to an elevation of 939-ft directly next to the OGB.

The OGB provides support for SR and NSR equipment & piping. The fan room and foyer are the only portions of the structure that house SR components. All maintenance and inspection platforms, stairs and ladders are separated from the SR components by concrete walls and/or floors and therefore are not within the scope of this AMR. More information on the Off-Gas Storage and Compressor Building is found in Section 12.2.2.8 of the USAR.

<u>Boundary</u>

The boundary for the Off-Gas Storage and Compressor Building includes the structure itself (foundation, walls, floors & roof) and various supports for SR and NSR equipment & piping. Mechanical systems, electrical equipment, component supports, and associated commodities inside the Off-Gas Storage Compressor Building are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The Off-Gas Storage and Compressor Building boundaries are shown on the following SLRBD:

SLR-36444

<u>System Intended Functions</u>

SR functions (10 CFR 54.4(a)(1)):

(1) Provides storage and controlled release of gaseous radioactive wastes, housing SR and NSR equipment, and provides radiation shielding.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Portions of the OGB are NSR, platforms, stairs, ladders, etc., however, failure of these components may affect SR components.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None

<u>USAR References</u>

Section 12.2

Components Subject to AMR

Table 2.4-12 lists the Off-Gas Storage and Compressor Building component types that require AMR and their associated component intended functions.

Table 3.5.2-12 provides the results of the AMR.

Table 2.4-12
Off-Gas Storage and Compressor Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Concrete: Interior Walls, Ceiling, and Floor	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Doors	Flood Barrier Shelter, Protection
Miscellaneous Structural Components	Structural Support
Structural Bolting	Structural Support

2.4.13 Plant Control and Cable Spreading Structure

Description

The plant control and cable spreading structure is a three-story box-like reinforced structure. The three stories include a basement story partially below grade and two stories above grade. Basement floor is at the 928-ft elevation. Ground floor is approximately four feet above grade at the 939-ft elevation and is also the floor of the cable spreading room. The MCR floor is at the 951-ft elevation. Floors at the 939-ft and 951-ft elevations are reinforced concrete slabs supported on structural steel beam and girder framing. Reinforced concrete walls extend from the basement floor to the 963-ft elevation providing closure on four sides for the cable spreading and control rooms. The walls support the floor framing at the 939-ft and 951-ft elevations plus a 2-foot thick two-way reinforced concrete slab at the 965-ft elevation which spans and encloses the control room. The walls are based on a reinforced concrete mat-type foundation supported on select fill.

The plant control and cable spreading structure includes the administration building which is a three-story building with a full basement. The basement walls are reinforced concrete. The remainder of the building construction is structural steel frame. The basement floor is a concrete slab at the 928-ft elevation, the other three floors are reinforced concrete on steel.

Information on the plant control and cable spreading structure is found in Section 12.2.2.3 of the USAR.

Boundary

The boundary for the plant control and cable spreading structure includes the foundation, walls, floors, and roof of the original office and control building as well as the two additions to the building. The original office and control building contains the cable spreading room, battery rooms, and the control room. The second addition includes the operational support center. The boundary also includes various structural steel and fasteners, doors, door seals, and grout. Mechanical systems, electrical equipment, component supports, and associated commodities inside the plant control and cable spreading structure are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The plant control and cable spreading structure boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides, under all operating or postulated accident conditions, safe enclosure for those portions of the standby electrical power systems and instrumentation and controls systems vital to overall plant operation and safety which are located therein and an environment satisfactory for continuous occupancy by operating personnel.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Portions of the plant control and cable spreading structure are NSR, and their failure could affect the capability of SR SSCs to perform their safety function.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) SSCs are considered in-scope due to FP, SBO and ATWS.

USAR References

Section 12.2

Components Subject to AMR

Table 2.4-13 lists the plant control and cable spreading structure component types that require AMR and their associated component intended functions.

Table 3.5.2-13 provides the results of the AMR.

Table 2.4-13
Plant Control and Cable Spreading Structure Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support
Concrete: Interior Walls, Ceiling, and Floor	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support
Control Room Seals	Pressure Boundary Flood Barrier
Masonry (Block) Walls	Flood Barrier Structural Support
Miscellaneous Structural Components	Structural Support
Structural Bolting	Structural Support

2.4.14 Radioactive Waste Building

Description

The Radioactive Waste Building is a concrete and steel framed structure that abuts (with a 1-inch seismic gap) the Reactor Building on the north side and adjoins the Radioactive Waste Shipping Building on the west side. It is supported by a slab at grade (floor EL. 935-ft), with perimeter footings below the walls on the east, south and west sides. The east side of the building consists of the Reactor Building rail car/truck bay. This bay, which is structurally monolithic with, but sealed from, the rest of the Radioactive Waste Building, is a part of secondary containment.

The structure is principally cast-in-place reinforced concrete. However, a significant area of the 947-ft floor consists of a lightly reinforced slab over steel framing. The rail car bay roof consists of built up roofing over steel framing and decking. The remaining roof areas consist of lightly reinforced slabs supported by structural steel. The walls are cast in place concrete.

An airlock connects the Radioactive Waste Building to the Reactor Building at the 935-ft level. The airlock door in the Reactor Building wall is a part of that building. The remaining doors and the enclosing walls & ceiling are part of the Radioactive Waste Building.

More information on the Radioactive Waste Building is found in Sections 12.2.1.3 and 12.3.2.2.3 of the USAR.

Boundary

The boundary for the Radioactive Waste Building includes the building structure itself (foundation, framing, walls, floors & roof) and those structural elements within or on the building that affect the LR function. The Radioactive Waste Shipping Building is treated as a separate structure. Mechanical systems, electrical equipment, component supports and associated commodities inside the Radioactive Waste Building are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The Radioactive Waste Building boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) The rail car bay and the EL. 935-ft airlock provide secondary containment, limiting offsite exposures to allowable levels.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Certain modes of building failure could result in a breach of the secondary containment boundary and / or damage to Category (1) items housed in the Reactor Building.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

None

USAR References

Section 5.3

Components Subject to AMR

Table 2.4-14 lists the Radioactive Waste Building component types that require AMR and their associated component intended functions.

Table 3.5.2-14 provides the results of the AMR.

Table 2.4-14
Radioactive Waste Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Airlock and Railroad Doors	HELB Barrier Pressure Boundary Shelter, Protection
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Concrete: Interior Walls, Ceiling, and Floor	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support
Masonry (Block) Walls	Flood Barrier Structural Support
Miscellaneous Structural Components	Structural Support
Railroad Bay Door View Port	Pressure Boundary
Roofing Railroad Bay	Pressure Boundary Shelter, Protection
Secondary Containment Seals	Shelter, Protection
Structural Bolting	Structural Support

2.4.15 Reactor Building

Description

The RB is a concrete and steel framed structure with a mat foundation. Approximate plan dimensions are 138 feet by 138 feet up to EL. 1001-ft. The north wall of the building is stepped back at this level; plan dimensions above the 1001-ft elevation are 105 feet (N-S) by 138 feet (E-W). Overall height is 177 feet from the top of the basemat, at EL. 896-ft, to the roof. The 8-foot thick basemat is founded on dense sand at an elevation of 888-ft. The structure is principally cast-in-place reinforced concrete up to the refueling floor at EL. 1028-ft. The superstructure covering the refueling floor consists of a steel frame enclosed with metal siding and elastomer membrane roofing. There is a small air intake penthouse on the partial roof at EL. 1001-ft.

The primary containment drywell and sacrificial shield occupy the central part of the Reactor Building up to the 1001-ft level; the drywell head extends above that level. The primary containment torus occupies most of the lowest floor (EL. 896-ft) of the building. The next four levels of the building (Elevations 935-ft, 962-ft, 986-ft, and 1001-ft) enclose various reactor auxiliaries, cooling equipment, ventilation equipment, radwaste equipment, storage areas, and shops.

The top floor of the Reactor Building at EL. 1028-ft is the refueling floor. This is an open floor that provides working and storage areas during refueling outages. The spent fuel storage pool, dryer/separator storage pool, and reactor well occupy about a quarter of the floor area.

The exterior walls of the Reactor Building are concrete up to the 1028-ft level. Interior walls are principally concrete and masonry block. Many of these provide radiation shielding. In addition, there are several drywall partitions that serve as fire walls.

There are numerous doors through both exterior and interior walls. Many of these provide a secondary containment and/or FP function. In addition, there are many piping and ductwork penetrations through the walls. Penetrations through exterior walls are sealed to limit leakage. Blow out panels are fitted into openings in the north wall of the steam chase. In the event of a steam or feed water line break within the chase, the panels fall outward (if differential pressure approaches 0.25 Pounds Per Square Inch (psi)) to vent steam into the Turbine Building and prevent over pressurization of the Reactor Building.

A rail car/truck bay on the southeast corner of the building provides access to the outside at the 935-ft level. This bay has doors at each end to allow moving equipment in and out of the Reactor Building without breaking containment. It is, therefore, included within the secondary containment boundary. The bay is, however, structurally a part of the Radwaste Building. Complete descriptions of the Reactor Building are given in USAR Sections 5.3 and 12.2.2.1.

Boundary

The boundary for the Reactor Building includes the building structure itself (foundation, framing, walls, floors, sacrificial shield wall, drywell pedestal, & roof), doors, floor hatch covers, various interior structural assemblies, the refueling floor cavities, the new & spent fuel racks, and embedded steel base plates for component supports. The primary containment, which is completely enclosed by the Reactor Building, is evaluated in Section 2.4.1 above; mechanical systems, electrical equipment, component supports, and associated commodities inside the Reactor Building are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The Reactor Building boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides secondary containment, limiting offsite exposures to allowable levels. The Reactor Building performs this function in conjunction with the Standby Gas Treatment System, which processes contaminated air exhausted from the structure.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Supports and protects (from external missiles, flooding, and the outside environment) Category (1) systems, structures, & components.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Protects enclosed structures, components, and commodities from external fires, ATWS, and station blackout.

USAR References

Sections 5.3 and 12.2.2.1

Components Subject to AMR

Table 2.4-15 lists the Reactor Building component types that require AMR and their associated component intended functions.

Table 3.5.2-15 provides the results of the AMR.

Table 2.4-15
Reactor Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support
Concrete: Interior Walls, Ceiling, and Floor	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support
Doors and Frames	Flood Barrier HELB Barrier Pressure Boundary Shelter, Protection
Fuel Storage Racks (New Fuel)	Structural Support
Fuel Storage Racks: Neutron Absorbing Sheets	Absorb Neutrons
Masonry (Block) Walls	Flood Barrier HELB Barrier Structural Support
Miscellaneous Structural Components	Flood Barrier Structural Support

Table 2.4-15
Reactor Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Seals and Roofing	Flood Barrier Pressure Boundary Shelter, Protection
Siding	Pressure Boundary Shelter, Protection
Spent Fuel Pool Liner, Dryer / Separator Storage Pool Liner, Reactor Well Liner	Pressure Boundary Structural Support
Spent Fuel Pool Gates	Pressure Boundary
Spent Fuel Storage Racks	Structural Support
Structural Bolting	Structural Support

2.4.16 Structures Affecting Safety

Description

This section covers aging management as it relates to plant structures that perform no safety or regulated event function but that could, under certain failure scenarios, adversely affect buildings or equipment having such functions. The structures within the scope of this section are collectively referred to as structures affecting safety. These are listed below.

- Heating boiler house
- Non-1E electrical equipment room
- 13.8 kV room
- Turbine Building addition
- Recombiner Building
- Radwaste Storage and New Shipping Building

Each of these structures abuts one or more of the following buildings that perform a SR function and/or house equipment essential to safety.

- Turbine Building
- Emergency Filtration Train Building
- Emergency Diesel Generator Building
- Radioactive Waste Building
- Reactor Building

Boundary

The boundary for the structures affecting safety includes the building structures themselves (foundation, framing, walls, floors, and roof), doors, and various interior structural assemblies. Mechanical systems, electrical equipment, component supports, and associated commodities inside the structures affecting safety are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The structures affecting safety boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

None

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) Certain postulated modes of building failure could result in a breach of the Reactor Building secondary containment boundary and/or damage to Category (1) items housed in the Reactor, EFT, Turbine and Emergency Diesel Generator Buildings.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) The Heating Boiler House provides support for a part of the cable spreading room Halon system and there is a fire door in the 13.8 kV room, and therefore, performs a fire protection function.

USAR References

None.

Components Subject to AMR

Table 2.4-16 lists the structures affecting safety component types that require AMR and their associated component intended functions.

Table 3.5.2-16 provides the results of the AMR.

Table 2.4-16
Structures Affecting Safety Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Concrete: Interior Walls, Ceiling, and Floor	Flood Barrier Missile Barrier Shelter, Protection Structural Support
Miscellaneous Structural Components	Structural Support
Structural Bolting	Structural Support

2.4.17 Turbine Building

Description

The Turbine Building is a concrete and steel framed Class 2 structure with the principal functions to house the turbine-generator, condenser, turbine-generator auxiliary systems, condensate demineralizer, moisture separators, condensate pumps, feedwater heaters, and reactor feed pumps. It houses Class 1 equipment as well as Appendix R safe shutdown equipment and equipment required to support the station blackout and the ATWS events.

The Turbine Building is supported by a reinforced concrete mat founded on dense sand underlain by a layer of stiff clay. Above the EL. 951-ft level, the perimeter wall consists of structural steel framing with metal siding.

The Turbine Building is discussed in USAR Section 12.2.2.5.

Boundary

The boundary for the Turbine Building includes the building structure itself (foundation, framing, walls, floors, and roof), doors, hatch covers, structural support assemblies including their members welds, bolted connections, anchorage, and concrete/grout at anchorage points. Mechanical systems, electrical equipment, piping, and component supports, and associated commodities inside the Turbine Building are evaluated in the AMRs applicable to those systems/commodities. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The Turbine Building boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides support and protection for SR SSCs.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

(1) The Turbine Building abuts the Reactor Building, the plant control & cable spreading structure, the EFB, and the DGB. The Turbine Building performs a Category (2) function in that certain modes of building failure could result in a breach of secondary containment boundary and/or damage to Category (1) items housed in these abutting Class 1 structures.

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) The Turbine Building houses SSCs in-scope due to fire protection, SBO, and ATWS.

USAR References

Section 12.2.2.5

Components Subject to AMR

Table 2.4-17 lists the Turbine Building component types that require AMR and their associated component intended functions.

Table 3.5.2-17 provides the results of the AMR.

Table 2.4-17
Turbine Building Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural Support
Concrete: Exterior Walls and Roof	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support
Concrete: Interior Walls, Ceiling, and Floor	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support
Doors	Flood Barrier HELB Barrier
Expansion Plugs	Flood Barrier
Joint and Penetration Seals	Flood Barrier HELB Barrier Shelter, Protection
Masonry (Block) Walls	Flood Barrier HELB Barrier Missile Barrier Radiation Shielding Structural Support
Miscellaneous Structural Components	Flood Barrier Structural Support
Structural Bolting	Structural Support

2.4.18 Underground Duct Bank

Description

The underground duct bank is classified as nuclear SR and is a Class 1 structure. The underground duct bank runs between the third floor of the EFB and the Reactor Building. The primary function of the duct bank is to carry Division II safe shutdown cables outside of areas where fire damage could occur. The duct bank includes risers at each end with an underground section in between. The underground portion of the duct bank is 700 feet in length and is rectangular in cross section. It is constructed of reinforced concrete and contains sixteen 4-inch diameter raceways. Access to the duct bank is provided by four reinforced concrete manholes. Seismic joints occur at the manhole to duct bank interface and the riser to duct bank interface. Additional details of the underground duct bank can be found in the USAR Section 12.2.

Boundary

The boundary for the underground duct bank includes the passive portions that are considered a part of the structure including concrete and carbon steel, low alloy steel components. There are no significant differences between the current boundaries and those identified as part of the initial MNGP LR effort.

The underground duct bank boundaries are shown on the following SLRBD:

SLR-36444

System Intended Functions

SR functions (10 CFR 54.4(a)(1)):

(1) Provides structural support, safe enclosure, and protection for SR cables.

NSR components that could affect SR functions (10 CFR 54.4(a)(2)):

None

FP, EQ, ATWS, and SBO functions (10 CFR 54.4(a)(3)):

(1) Provides support for the protection of Appendix R safe shutdown equipment from a fire in redundant division areas and performing functions relied upon for 10 CFR 50.63, specifically equipment support protection to provides structural and or functional support to equipment relied upon for SBO mitigation.

USAR References

Section 12.2

Components Subject to AMR

Table 2.4-18 lists the underground duct bank component types that require AMR and their associated component intended functions.

Table 3.5.2-18 provides the results of the AMR.

Table 2.4-18
Underground Duct Bank Components Subject to Aging Management Review

Component Type	Component Intended Function(s)
Concrete: Basemat, Foundation	Structural support
Concrete: Exterior Walls and Roof	Flood Barrier Shelter, Protection Structural Support
Concrete: Interior Walls, Ceiling, and Floor	Flood Barrier Shelter, Protection Structural Support
Manhole Covers, Supports	Flood Barrier Missile Barriers Shelter, Protection
Miscellaneous Structural Components	Structural Support
Structural Bolting	Structural Support

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION & CONTROLS

The determination of electrical systems within the scope of SLR is made by initially identifying electrical and I&C systems and their design functions. Each system is then reviewed to determine those that satisfy one or more of the criteria contained in 10 CFR 54.4. This process is described in Section 2.1.4 and the results of the electrical and I&C systems review are included in Table 2.2-1. Section 2.1 also provides the methodology for determining the components/commodities within the scope of 10 CFR 54.4 that meet the requirements contained in 10 CFR 54.21(a)(1). The components/commodities that meet these screening requirements are identified in this section. These identified components/commodities require an AMR for SLR.

The in-scope electrical and I&C systems are described in Section 2.5.1. Electrical commodities are described in Section 2.5.2. Supports for electrical cables, cable trays, conduits, cabinets, and enclosures are addressed in the Hangers and Supports Commodity Group (Section 2.4.7).

2.5.1 Electrical and I&C Component Commodity Groups

2.5.1.1 Identification of Electrical and I&C Components

The electrical and I&C component commodity groups were identified from a review of electrical systems within the scope of 10 CFR 54, controlled electrical drawings, SAP, and interface with parallel mechanical and structural screening efforts. This commodity-based approach, whereby component types with similar design and/or functional characteristics are grouped together, is consistent with guidance from NEI 17-01 and Table 2.1-6 of NUREG-2192. The in-scope electrical and I&C component commodity groups identified at MNGP are listed in Table 2.5-1.

2.5.1.2 Application of Screening Criteria 10 CFR 54.21(a)(1)(i) to Electrical and I&C Commodity Groups

Following the 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)
- Cable bus
- Cable tie-wraps
- Insulated cables and connections
- Electrical and I&C penetration assemblies
- Fuse holders, metallic clamps (not part of active equipment)
- High-voltage electrical insulators
- Metal enclosed bus
- Switchyard bus
- Transmission conductors and connectors
- Uninsulated ground conductors

2.5.1.3 Elimination of Electrical and I&C Commodity Groups Not Applicable to MNGP

The following electrical and I&C commodity groups are not applicable to MNGP:

Cable Tie-Wraps

Tie-wraps are used in cable installations as cable ties. Cable ties hold groups of cables together for restraint, ease of maintenance and to keep the wire cable runs neat and orderly. There are no current license basis requirements for MNGP that cable tie-wraps remain functional during and following DBEs. Electrical cable tie-wraps do not function as cable supports in raceway support analyses; therefore, the installation and inspection criteria are limited to the application of standard practices in providing quality cable bundles and cable placement. The seismic qualification of cable trays does not credit the use of electrical cable tie-wraps. Cable tie-wraps are not credited in the MNGP design basis and have no SLR intended functions as defined in 10 CFR 54.4(a). Therefore, cable tie-wraps are not within the scope of SLR and therefore, are not subject to AMR.

Cable Bus

Cable bus is a variation on metal enclosed bus which is similar in construction to a metal enclosed bus, but instead of segregated or nonsegregated electrical buses, cable bus comprises a fully enclosed metal enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus may omit the top cover or use a louvered top cover and enclosure. Both the cable bus and enclosures are not sealed against intrusion of dust, industrial pollution, moisture, rain, ice and, therefore, may introduce debris into the internal cable bus assembly. Cable bus is not utilized at MNGP. Accordingly, cable bus is not subject to AMR.

Uninsulated Ground Conductors

Uninsulated ground conductors are electrical conductors (e.g., copper cable, copper bar, steel bar) that are uninsulated (bare) and are used to make ground connections for electrical equipment. Uninsulated ground conductors are connected to electrical equipment housings and electrical enclosures as well as metal structural features such as the cable tray system and the building structural steel. Uninsulated ground conductors enhance the capability of the electrical system to withstand electrical system disturbances (such as electrical faults, lightning surges) for equipment and personnel protection. Uninsulated ground conductors are always isolated from the electrical operating circuits and are not required for those circuits or equipment to perform their intended functions. Uninsulated ground conductors are connected by compression or fusion (soldered or welded) connections to interfacing equipment. Compression and fusion connections involve various types of metals and other inorganic materials that have no aging effects that would result in loss of intended function.

Uninsulated ground cables are not classified as SR nor are they relied upon for SR equipment to perform their intended function as identified in 10 CFR 54.4. Failure of an uninsulated ground conductor will not prevent the satisfactory accomplishment of any functions identified in 10 CFR 54.4(a)(1). Uninsulated ground cables are not relied upon in safety analyses or plant calculations to perform a function related to any regulated events identified by 10 CFR 54.4(a)(3). The OE review did not show any significant adverse industry experience associated with uninsulated grounding cables.

Based on the above, uninsulated ground cables are not subject to AMR.

2.5.1.4 Application of Screening Criteria 10 CFR 54.21(a)(1)(ii) to Electrical and I&C Commodity Groups

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 of Electric Equipment (B.2.2.3) program. This is because electrical and I&C components and commodities included in the Environmental Qualification of Electric Equipment (B.2.2.3) 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 Environmental Qualification of Electric Equipment (B.2.2.3) program are subject to AMR in accordance with the screening criteria of 10 CFR 54.21(a)(1)(ii). See Section 4.4 for the TLAA evaluation of the Environmental Qualification of Electric Equipment (B.2.2.3) program. The remaining commodities, all, or part of which are not in the Environmental Qualification of Electric Equipment (B.2.2.3) program, require AMR.

After applying the screening criteria discussed above, including the guidance NEI 17-01 the following commodities which require AMR are discussed below.

<u>Cable Connections (Metallic Parts)</u>

The Cable Connectors (Metallic Parts) commodity includes metallic portions of cable connections that are not included in the Environmental Qualification of Electric Equipment (B.2.2.3) program. The metallic connections evaluated include splices, threaded connectors, compression type termination lugs, and terminal blocks. Therefore, the Cable Connections (Metallic Parts) commodity meets the screening criterion of 10 CFR 54.21(a)(1)(ii) and is subject to AMR.

<u>Insulated Electrical Cables and Connections</u>

The insulated cables and connections commodities are separated for AMR 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
    - Insulating Portions of Fuse Holders
- 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

The function of Insulated Electrical Cables and Connections is to electrically connect specified sections of an electrical circuit to deliver voltage, current, or signals. Electrical cables and their required terminations (i.e., connections) are reviewed as a single component commodity group. The types of connections included in this review are splices, connectors, and terminal blocks. Numerous insulated cables and connections are included in the Environmental Qualification of Electric Equipment (B.2.2.3) program. The insulated cables and connections that are included in this program have a qualified life that is documented in the Environmental Qualification of Electric Equipment (B.2.2.3) program. Components in the Environmental Qualification of Electric Equipment (B.2.2.3) program are replaced prior to the expiration of their qualified life. Accordingly, all insulated cables and connections within the Environmental Qualification of Electric Equipment (B.2.2.3) program are replacement items under 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR. Note that TLAAs associated with electrical/I&C components within the Environmental Qualification of Electric Equipment (B.2.2.3) program are discussed in Section 4.4.

Insulated cables and connections that perform an intended function within the scope of SLR but are not included in the Environmental Qualification of Electric Equipment (B.2.2.3) program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

<u>Electrical and I&C Penetration Assemblies</u>

For an electrical penetration to be within the scope of LR, it must support an intended function of one of the systems or components identified as within the scope of SLR. MNGP uses penetrations manufactured by General Electric (GE) and D.G. O'Brien. There are 24 electrical penetrations at the MNGP. Twenty of these are in use and four are spares. There are six penetrations designated as requiring EQ and are addressed in Section 4.0, *Time Limited Aging Analysis*. Therefore, electrical and I&C penetration assemblies in the Environmental Qualification of Electric Equipment (B.2.2.3) program do not meet the criterion of 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR. Of the remaining 14 penetrations, only four are in-scope for LR. The other ten penetrations do not contain cables which provide a LR SR intended function or are credited for any of the regulated events. Electrical and I&C penetration assemblies that are within the scope of SLR, but not included in the Environmental Qualification of Electric Equipment (B.2.2.3) program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

<u>Fuse Holders (not part of active equipment)</u>

The Fuse Holders commodity includes fuse holders that are not part of a larger active assembly and are not included in the Environmental Qualification of Electric Equipment (B.2.2.3) program. The metallic portions of fuse holders that are not part of a larger active assembly and are not included in the Environmental Qualification of

Electric Equipment (B.2.2.3) program meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

Switchyard Bus and Connections, Transmission Conductors and Connections, High-Voltage Electrical Insulators

NUREG-2191, Chapter VI.A, addresses components that are relied upon to meet the SBO requirements for restoration of offsite power. This guidance is consistent with the guidance provided to the original LR applicants under NRC letter dated April 1, 2002 (Reference ML020920464). An evaluation was performed as part of the initial MNGP LR effort to determine the restoration power path for offsite power following an SBO event based on the guidance of the NRC letter. The switchyard commodities of switchyard bus and connections, high-voltage electrical insulators, transmission conductors and connections, metal enclosed bus, and inaccessible medium voltage cables perform an intended function for restoration of offsite power following an SBO event. These commodities are not included in the Environmental Qualification of Electric Equipment (B.2.2.3) program. Thus, these commodities meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR. The electrical interconnection between MNGP and the offsite transmission network and the off-site power recovery paths following an SBO are shown in Figure 2.5-1.

Metal Enclosed Bus

Metal enclosed bus (MEB) is used to connect two or more elements (i.e., electrical equipment such as switchgear and transformers) of an electrical circuit. This commodity group includes three broad categories of MEB; isolated (iso) phase bus, non-segregated phase bus, and segregated phase bus. Iso-phase bus is electrical bus in which each phase conductor is enclosed by an individual metal housing separated from adjacent conductor housings by an air space. Non-segregated phase bus is electrical bus constructed with all phase conductors in a common enclosure without barriers (only air space) between the phases. Segregated phase bus is electrical bus constructed with all phase conductors in a common enclosure but segregated by metal barriers between phases. Segregated phase bus is not utilized at MNGP, and the iso-phase bus does not perform or support a SLR intended function. Only nonsegregated MEB in the 13.8 kV and 4.16 kV systems perform a SLR intended function, and none of this MEB is in the Environmental Qualification of Electric Equipment (B.2.2.3) program. Therefore, non-segregated MEB in the 13.8 kV and 4.16 kV systems meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

2.5.2 Electrical and I&C Component Commodity Groups Subject to Aging Management Review

Table 2.5-2 lists the electrical and I&C commodity groups that require AMR and their associated component intended functions.

Table 3.6.2-1 provides the results of the AMR.

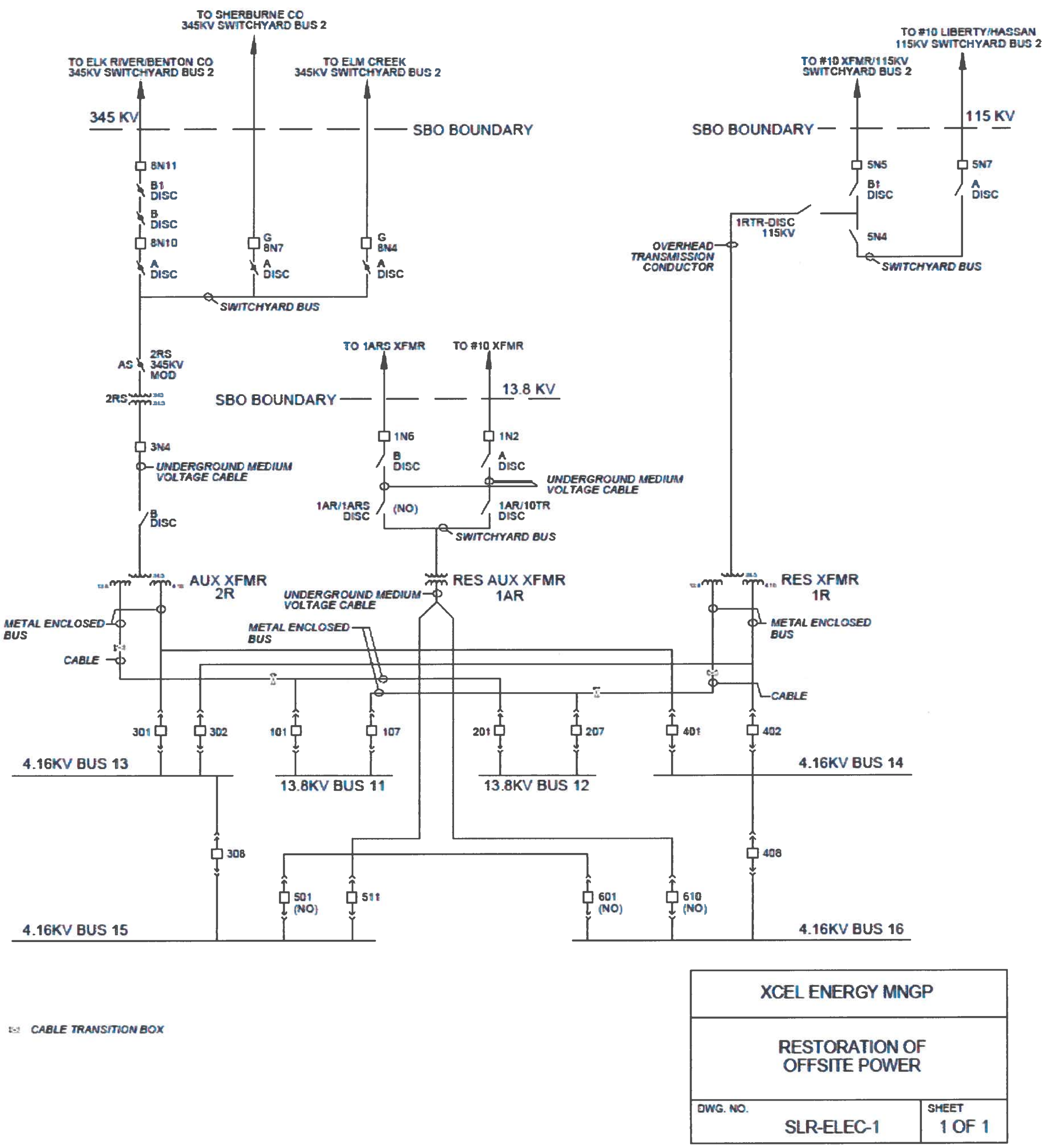
Table 2.5-1
Electrical and I&C Component Commodity Groups Installed at MNGP for In-Scope Systems

Alarm Units	Electrical/I&C Penetration Assemblies	Light Bulbs	Signal Conditioners
Analyzers		Load Centers	Solenoid Operators
		Loop Controllers	Solid State Devices
Annunciators	Elements	Meters	Splices
Batteries	Fuse Holders	Motor Control Centers	Surge Arresters
Cable Bus	Fuses	Motors	Switches
Cable Connections (Metallic Parts)			
Cable Tie-Wraps	Generators		
Chargers			
Circuit Breakers	Electric Heaters	Power Distribution Panels	Switchgear
Converters	Heat Tracing	Power Supplies	Switchyard Bus
Communication Equipment	High-Voltage Insulators	Radiation Monitors	Terminal Blocks
Electrical Bus (aka Metal-Enclosed Bus)	Indicators	Recorders	Thermocouples
	Insulated Cables and Connections	Regulators	Transducers
Electrical Controls and Panel Internal Component Assemblies		Relays	Transformers
	Inverters	RTDs	Transmission Conductors and Connections
	Isolators	Sensors	Transmitters
			Uninsulated Ground Conductors

Table 2.5-2
Electrical and I&C System Commodity Groups Subject to Aging Management Review

Structure and/or Component/ Commodity	Component Intended Function(s)
Non-EQ Insulated Cables and Connections	Electrical Continuity
Electrical portions of non-EQ Electrical/I&C Penetration Assemblies	Electrical Continuity
Metal Enclosed Bus	Electrical Continuity Insulate (electrical) Shelter, Protection
Fuse Holders, metallic clamps (not part of an active assembly)	Electrical Continuity
High-Voltage Electrical Insulators (for SBO recovery)	Insulate (electrical)
Switchyard Bus and Connections (for SBO recovery)	Electrical Continuity
Transmission Conductors and Connections (for SBO recovery)	Electrical Continuity
Cable Connections (Metallic Parts)	Electrical Continuity

Figure 2.5-1
MNGP Simplified One-Line Diagram (For SBO Offsite Power Recovery)



3.0 AGING MANAGEMENT REVIEW RESULTS

This chapter provides the results of the AMR for those systems and structures in the scope of SLR as shown in Table 2.2-1. Organization of this chapter is based on Tables 3.1-1 through 3.6-1 of NUREG-2192.

The major sections of this chapter are:

- Aging Management of Reactor Vessels, Internals, and Reactor Coolant System (Section 3.1)
- Aging Management of Engineered Safety Features (Section 3.2)
- Aging Management of Auxiliary Systems (Section 3.3)
- Aging Management of Steam and Power Conversion Systems (Section 3.4)
- Aging Management of Containments, Structures, and Component Supports (Section 3.5)
- Aging Management of Electrical and Instrumentation and Controls (Section 3.6)

Descriptions of the service environments that were used in the mechanical systems AMR to determine aging effects requiring management are included in Table 3.0-1, Mechanical System Service Environments. The environments used in the AMRs are listed in the Environment column. The third column identifies one or more of the NUREG-2191 environments that were used when comparing the MNGP AMR results to the NUREG-2191 results. Structural service environments are in Table 3.0-2 and electrical service environments are in Table 3.0-3. The definitions of those environments correspond to the definitions in NUREG-2191, Section IX.D.

The remaining AMR results information in Section 3 is presented in the following two tables:

Table 3.x-1 - where “3” indicates the SLRA section number, “x” indicates the subsection number from NUREG-2191, and '1' indicates that this is the first table type in Section 3. For example, in the Reactor Vessels, Internals, and Reactor Coolant System subsection, this table would be number Table 3.1-1, in the ESF subsection, this table would be Table 3.2-1, and so on. For ease of discussion, this table will, hereafter, be referred to in this section as “Table 1.”

Table 3.x.2-y - where “3” indicates the SLRA section number, “x” indicates the subsection number from NUREG-2191, and '2' indicates that this is the second table type in Section 3; and 'y' indicates the table number for a specific system. For example, for the RPV, within the Reactor Vessels, Internals, and Reactor Coolant System subsection, this table would be Table 3.1.2-1 and for the RIT System, it would be Table 3.1.2-2. For the CSP System, within the ESF subsection, this table would be Table 3.2.2-1. For the next system within the ESF subsection, it would be Table 3.2.2-2. For ease of discussion, this table will, hereafter, be referred to in this section as “Table 2."

Table Description

Table 1

The purpose of Table 1 is to provide a summary comparison of how the facility aligns with the corresponding tables of NUREG-2192. The table is essentially the same as Tables 3.1-1 through 3.6-1 provided in NUREG-2192, except that the "New, Modified, Deleted, Edited Item," "ID" and "Type" columns have been replaced by an "Item Number" column, and the "GALL-SLR Item" column has been replaced by a "Discussion" column.

The "Item Number" column provides the reviewer with a means to cross-reference from Table 2 to Table 1.

The "Discussion" column is used to provide clarifying or amplifying information. The following are examples of information that might be contained within this column:

- "Further Evaluation Recommended" information or reference to where that information is located
- The name of a plant-specific AMP being used, if applicable
- Exceptions to the NUREG-2191 assumptions, if applicable
- A discussion of how the line is consistent with the corresponding line item in NUREG-2191, when that may not be intuitively obvious
- A discussion of how the item is different than the corresponding line item in NUREG-2191 when it may appear to be consistent (e.g., when there is exception taken to an AMP that is listed in NUREG-2191), if applicable

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 row with the corresponding NUREG-2192 table row, thereby allowing for the ease of checking consistency.

Table 2

Table 2 provides the detailed results of the AMRs for those components identified in SLRA section 2 as being subject to AMR. There is a Table 2 for each of the systems within a Chapter 3 section grouping. For example, the ESF subsection group contains tables specific to the following systems: CSP, HPCI, PCM, RCIC, RHR, and SCT. Table 2 consists of the following nine columns:

- Component Type
- Intended Function
- Material
- Environment
- Aging Effect Requiring Management
- AMPs
- NUREG-2191 Item
- Table 1 Item
- Notes

Component Type - The first column identifies all of the component types from Section 2 of the SLRA that are subject to AMR. They are listed in alphabetical order.

Intended Function - The second column contains the SLR intended functions for the listed component types. Definitions of intended functions are contained in Table 2.1-1.

Material - The third column lists the particular materials of construction for the component type.

Environment - The fourth column lists the environments to which the component types are exposed. Service environments are indicated, and a list of mechanical system service environments is provided in Table 3.0-1. The Structural and Electrical AMRs use environment names consistent with the assigned NUREG-2191 items and shown in Table 3.0-2 and Table 3.0-3, respectively. The definitions of those environments correspond to the definitions in NUREG-2191, Section IX.D.

Aging Effect Requiring Management - As part of the AMR process, the aging effects that are required to be managed in order to maintain the intended function of the component type are identified for the material and environment combination. These aging effects requiring management are listed in the fifth column.

Aging Management Programs - The AMPs used to manage the aging effects requiring management are listed in the sixth column of Table 2. AMPs are described in Appendix B.

NUREG-2191 Item - Each combination of component type, material, environment, aging effect requiring management, and AMP that is listed in Table 2, is compared to NUREG-2191, with consideration given to the standard notes, to identify consistency. Consistency is documented by noting the appropriate NUREG-2191 item number in the seventh column of Table 2. If there is no corresponding item number in NUREG-2191, this field in column seven is marked “None.” Thus, a reviewer can readily identify the correlation between the plant-specific tables and the NUREG-2191 tables.

Table 1 Item - Each combination of component, material, environment, aging effect requiring management, and AMP that has an identified NUREG-2191 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Table 1 is listed in the eighth column of Table 2. If there is no corresponding item in NUREG-2191, this field in column eight is marked “None.” The Table 1 Item allows correlation of the information from the two tables.

Notes - The notes provided in each Table 2 describe how the information in the table aligns with the information in NUREG-2191. Each Table 2 contains standard industry lettered notes and, if applicable, plant-specific numbered notes. The standard industry lettered notes (e.g., A, B, C) provide standard information regarding comparison of the AMR results with the NUREG-2191 Aging Management table line item identified in the seventh column. In addition to the standard industry lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

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, AMPs, and Further Evaluation Recommended information is taken directly from NUREG-2192, no further analysis of those columns is required.

The information intended to help the reviewer in this table is contained within the Discussion column. Here the reviewer will be given plant-specific information necessary to determine, in summary, how the evaluations and programs align with NUREG-2191. This may be in the form of descriptive information within the Discussion column, or the reviewer may be referred to other locations within the SLRA for further information. A statement of “Consistent with NUREG-2191” means that the Table 2 items that link to that Table 1 row are consistent with the material, environment, aging effect, and program(s) associated with the assigned NUREG-2191 row, followed by any clarifications or exceptions that may apply.

Table 2

Table 2 contains all of the AMR 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 AMP combination for a particular component type within a system. Within each system or structure, the intended functions for each component type are consolidated for table listing. In addition, if there is a correlation between the combination in Table 2 and a combination in NUREG-2191, this will be identified by a referenced item number in column seven, NUREG-2191 Item. The reviewer can refer to the item number in NUREG-2191, if desired, to verify the correlation. If the column contains “None,” no corresponding combination in NUREG-2191 was found. As the reviewer continues across the table from left to right, within a given row, the next column is labeled Table 1 Item. If there is a reference number in this column, the reviewer is able to use that reference number to locate the corresponding row in Table 1 and see how the AMP 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.

Table 3.0-1
Mechanical System Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Air - dry	Air that has been treated to reduce its dew point well below the system operating temperature and treated to control lubricant content, particulate matter, and other corrosive contaminants.	Air–dry
Air - indoor controlled	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment. This environment may have the potential to contain halides.	Air–indoor controlled
Air - indoor uncontrolled	This environment is for indoor locations that are sheltered/protected from weather. Surfaces of components in this environment may also be periodically exposed to condensation. This environment may have the potential to contain halides.	Air–indoor uncontrolled
Air - Indoor Uncontrolled <288°C	This environment consists of a metal temperature of BWR components <288°C [550°F].	System temperature up to 288°C [550°F]
Air - outdoor	The outdoor environment consists of atmospheric air, salt-laden air, ambient temperature and humidity, and exposure to precipitation. Surfaces of components in this environment may also be periodically exposed to condensation. This environment may have the potential to contain halides.	Air–outdoor
Closed cycle cooling water	A subset of treated water that is subject to the Closed Treated Water Systems (B.2.3.12) program. Examples include Reactor and Turbine Building closed cooling water systems, the closed portions of HVAC systems and diesel generator cooling water systems. Closed-cycle cooling water typically contains corrosion inhibitors and may also contain biocides or other additives.	Closed-cycle cooling water
Closed cycle cooling water >140°F	A subset of treated water that is subject to the Closed Treated Water Systems (B.2.3.12) program. Examples include Reactor and Turbine Building closed cooling water systems, the closed portions of HVAC systems and diesel generator cooling water systems. Closed-cycle cooling water typically contains corrosion inhibitors and may also contain biocides or other additives. Closed-cycle cooling water systems above 60 °C (>140 °F) exceed the threshold for SS SCC.	Closed-cycle cooling water

Table 3.0-1
Mechanical System Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Concrete	Components in contact with concrete. Concrete containing carbonate/bicarbonate can result in additional aging effects (e.g., SCC in carbon steel, etc.).	Concrete
Condensation	Condensation on the surfaces of systems at temperatures below the dew point facilitates loss of material in steel caused by general, pitting, and crevice corrosion. It also facilitates cracking in those materials susceptible to stress corrosion cracking due to the potential for internal or external surface contamination. Condensation can form between thermal insulation and a component when air intrusion occurs through minor gaps in the insulation and the operating temperature of the component is below the dew point of the penetrating air.	Condensation
Diesel exhaust	Gases, fluids, particulates present in diesel engine exhaust.	Diesel exhaust
Fuel oil	Diesel oil, No. 2 oil, or other liquid hydrocarbons used to fuel diesel engines.	Fuel oil
Gas	Internal dry non-corrosive gas environment such as N_2, carbon dioxide, Freon, and halon.	Gas
Lubricating oil	Lubricating oils are low-to medium-viscosity hydrocarbons used for bearing, gear, and engine lubrication. An oil analysis program may be credited to preclude water contamination. The lubricating oil environment does not include waste oil. Waste oil is included in the environment of waste water.	Lubricating oil
Raw water	Raw water is defined as water that enters the plant from a river, lake, pond, or rain/ground water source that has not been demineralized or chemically treated to any significant extent. The water may be rough-filtered to remove large particles. Biocides may be added to control microorganisms or macroorganisms. Although city water is purified for drinking purposes, it is conservatively classified as raw water for the purposes of AMR.	Raw water
Reactor coolant	Reactor coolant is treated water in the RCS and connected systems and is always assumed to be >482 °F (>250 °C).	Reactor coolant

Table 3.0-1
Mechanical System Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Reactor coolant >250 °C	Reactor coolant is treated water in the RCS and connected systems and is always assumed to be >482 °F (>250 °C). This applies to thermal embrittlement of CASS.	Reactor coolant
Reactor coolant and neutron flux	The reactor coolant and neutron flux environment should be selected for components within the reactor vessel system and reactor 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 be assumed to be >482°F.	Reactor coolant and neutron flux
Sodium pentaborate solution	Treated water that contains a mixture of borax and boric acid. This environment is used in the SLC System.	Sodium pentaborate solution
Soil	External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to groundwater in the soil. For the purposes of determining aging effects, the soil environment is assumed to include chlorides, sulfates, etc. The soil environment is applied to mechanical components (e.g., piping and tanks) buried in soil. Soil containing carbonate/bicarbonate can result in additional aging effects (e.g., SCC in carbon steel, etc.).	Soil
Steam	Steam, subject to a water chemistry program. In determining aging effects, steam is considered treated water. The steam environment is the internal environment associated with dry steam such as main steam up to the high pressure turbine. Wet steam is included in the treated water environment.	Steam
Treated water	Treated water is demineralized water and is the base water for all clean systems. Treated water generally contains minimal amounts of any additions. This water is generally characterized by high purity, low conductivity, and very low oxygen content.	Treated water
Treated water >140°F	Treated water above 140°F SCC threshold for SS.	Treated water >60°C [>140°F]

Table 3.0-1
Mechanical System Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Underground	Underground piping and tanks below grade but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection, is limited. When the underground environment is cited, the term includes exposure to air - outdoor, air - indoor uncontrolled, air, raw water, groundwater, and condensation.	Underground
Waste water	Water in liquid waste drains such as in liquid radioactive waste, oily waste, floor drainage, chemical waste water, and secondary waste water systems. Waste waters may contain contaminants, including oil and boric acid, as well as treated water not monitored by a chemistry program.	Waste water
Waste water >140°F	Water in liquid waste drains such as in liquid radioactive waste, oily waste, floor drainage, chemical waste water, and secondary waste water systems. Waste waters may contain contaminants, including oil and boric acid, as well as treated water not monitored by a chemistry program.	Waste water

Table 3.0-2
Structural Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Air - indoor controlled	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment. This environment may have the potential to contain halides.	Air–indoor controlled
Air - indoor uncontrolled	This environment is for indoor locations that are sheltered/protected from weather. Surfaces of components in this environment may also be periodically exposed to condensation. This environment may have the potential to contain halides.	Air–indoor uncontrolled
Air - outdoor	The outdoor environment consists of atmospheric air, ambient temperature and humidity, and exposure to precipitation. Surfaces of components in this environment may also be periodically exposed to condensation. This environment may have the potential to contain halides.	Air–outdoor
Concrete	This environment consists of components that are embedded in concrete.	Concrete
Groundwater/soil	Groundwater is subsurface water that can be detected in wells, tunnels, or drainage galleries, or that flows naturally to the earth's surface via seeps or springs. Soil is a mixture of organic and inorganic materials produced by the weathering of rock and clay minerals or the decomposition of vegetation. Concrete subjected to a groundwater/soil environment can be vulnerable to an increase in porosity and permeability, cracking, loss of material (spalling, scaling), or aggressive chemical attack. Other materials with prolonged exposures to groundwater or moist soils are subject to the same aging effects as those systems and components exposed to raw water.	Groundwater/soil
Treated water	Treated water is demineralized water and is the base water for all clean systems. Treated water generally contains minimal amounts of any additions. This water is generally characterized by high purity, low conductivity, and very low oxygen content.	Treated water

Table 3.0-2
Structural Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Water - flowing	Water that is refreshed; thus, it has a greater impact on leaching and can include rainwater, raw water, groundwater, or water flowing under a foundation.	Water-flowing
Water - standing	Water that is stagnant and unrefreshed, thus possibly resulting in increased ionic strength up to saturation.	Water-standing

Table 3.0-3
Electrical Service Environments

Environment	Description	Corresponding NUREG-2191 Environments
Air – indoor controlled	An environment where 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 (IR)).	Air – indoor controlled
Air – indoor uncontrolled	This environment is for indoor locations that are sheltered/protected from weather. Surfaces of components in this environment may also be periodically exposed to condensation.	Air – indoor uncontrolled
Air – outdoor	The outdoor environment consists of moist, possibly salt-laden air and spray, cooling tower plumes (which might contain chemical additives), industrial pollutants (e.g., fly ash, soot), ambient temperatures and humidity, and exposure to weather events, including precipitation and wind. The outdoor air environment also potentially includes component contamination due to animal infestation including by-products or excrement containing uric acid, ammonia, phosphates, or other compounds. The outdoor air environment can also result in submergence of components (particularly when they are in vaults) due to the potential for water to accumulate or due to external or internal buildup of condensation.	Air – outdoor
Adverse localized environments	An ALE is an environment limited to the immediate vicinity of a component that is hostile to the component material, thereby leading to potential aging effects. Electrical insulation used for electrical cables can be subjected to an ALE. ALEs can be due to any of the following: (1) exposure to significant moisture, or (2) exposure to heat, radiation, or moisture and are represented by specific GALL-SLR AMR items. Note that significant moisture is a wet environment for cable or connection insulation materials where the moisture lasts more than 3 days (e.g., cable submerged in standing water).	Adverse localized environment caused by heat, radiation, or moisture

3.1 AGING MANAGEMENT OF REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

3.1.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.3.1, *Reactor Coolant System* as being subject to AMR. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Reactor Pressure Vessel (Section 2.3.1.1)
- Reactor Vessel Internals (Section 2.3.1.2)
- Reactor Coolant Pressure Boundary and Connected Piping (Section 2.3.1.3)

3.1.2 Results

The following tables summarize the results of the AMR for the RCS.

Table 3.1.2-1, Reactor Pressure Vessel – Summary of Aging Management Evaluation

Table 3.1.2-2, Reactor Vessel Internals – Summary of Aging Management Evaluation

Table 3.1.2-3, Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation

3.1.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.1.2.1.1 Reactor Pressure Vessel

Materials

The materials of construction for the RPV components are:

- Carbon Steel
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- High-Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater
- Nickel Alloy
- Stainless Steel

Environment

The RPV components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Neutron Flux
- Reactor Coolant

Aging Effects Requiring Management

The following aging effects associated with the RPV require management:

- Cracking
- Cumulative Fatigue Damage
- Long-Term Loss of Material
- Loss of Fracture Toughness
- Loss of Material

Aging Management Programs

The following AMPs manage the aging effects for the RPV components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
- BWR Penetrations (B.2.3.6)
- BWR Stress Corrosion Cracking (B.2.3.5)
- BWR Vessel ID Attachment Welds (B.2.3.4)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Neutron Fluence Monitoring (B.2.2.2)
- One-Time Inspection (B.2.3.20)
- Reactor Head Closure Stud Bolting (B.2.3.3)
- Reactor Vessel Material Surveillance (B.2.3.19)
- Water Chemistry (B.2.3.2)

3.1.2.1.2 Reactor Vessel Internals

Materials

The materials of construction for the RIT System components are:

- Cast Austenitic Stainless Steel
- Nickel Alloy
- Stainless Steel

Environment

The RIT System components are exposed to the following environments:

- Reactor Coolant
- Neutron Flux

Aging Effects Requiring Management

The following aging effects associated with the RIT System require management:

- Cracking
- Cumulative Fatigue Damage
- Loss of Fracture Toughness

- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the RIT System components:

- BWR Vessel Internals (B.2.3.7)
- Water Chemistry (B.2.3.2)

3.1.2.1.3 Reactor Coolant Pressure Boundary and Connected Piping

Materials

The materials of construction for the RCPB and Connected Piping System components are:

- Carbon Steel
- Cast Austenitic Stainless Steel
- Nickel Alloy
- Stainless Steel

Environment

The RCPB and Connected Piping System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Air - Indoor Uncontrolled <550°F
- Closed-Cycle Cooling Water
- Condensation
- Gas
- Lubricating Oil
- Reactor Coolant
- Reactor Coolant >482°F
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the RCPB and Connected Piping System 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 AMPs manage the aging effects for the RCPB and Connected Piping System components:

- ASME Code Class 1 Small-Bore Piping (B.2.3.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
- ASME Section XI, Subsection IWF (B.2.3.30)
- Bolting Integrity (B.2.3.10)
- BWR Stress Corrosion Cracking (B.2.3.5)
- Closed Treated Water Systems (B.2.3.12)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.3.8)
- Water Chemistry (B.2.3.2)

3.1.2.2 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 SLR application. For the RCS, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.1.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). These types of TLAAs are addressed separately in Section 4.3, "Metal Fatigue," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage for applicable RCS components is an aging effect evaluated as a TLAA in Section 4.3, *Metal Fatigue*.

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

(1) Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG upper and lower shell and transition cone exposed to secondary feedwater and steam. The existing program relies on control of water chemistry to mitigate corrosion and inservice inspection (ISI) to detect loss of material. The extent and schedule of the existing SG inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, according to NRC Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist. Augmented inspection is recommended to manage this aging effect. Furthermore, this issue is limited to Westinghouse Model 44 and 51 Steam Generators, where a high-stress region exists at the shell to transition cone weld. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable. This further evaluation item is only applicable to Westinghouse Model 44 and 51 steam generators.

(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.

Not applicable. This further evaluation item is applicable to PWRs only.

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 1017 n/cm^2 (E >1 MeV) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, "Reactor Pressure Vessel Neutron Embrittlement Analysis," of this SRP-SLR.

Loss of fracture toughness due to neutron irradiation embrittlement is an aging effect and mechanism evaluated by a TLAA. The TLAA evaluation of neutron irradiation embrittlement is discussed in Section 4.2, *Reactor Vessel Neutron Embrittlement*.

(2) Loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. A reactor vessel material surveillance program monitors neutron irradiation embrittlement of the reactor vessel. The reactor vessel material surveillance program is either a plant-specific surveillance program or an integrated surveillance program, depending on matters such as the composition of limiting materials and the availability of surveillance capsules.

In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further NRC staff evaluation is required for a subsequent license renewal (SLR). Specific recommendations for an acceptable AMP are provided in GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance."

A neutron fluence monitoring program may be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the plant's reactor vessel neutron irradiation embrittlement TLAAs. These TLAAs are the subjects of the topics discussed in SRP-SLR Section 3.1.2.2.3.1 and "acceptance criteria" and "review procedure" guidance in SRP-SLR

Section 4.2. For those applicants that determine it is appropriate to include a neutron fluence monitoring AMP in their SLRAs, the program is to be implemented in conjunction with the applicant's implementation of an AMP that corresponds to GALL-SLR Report AMP XI.M31, "Reactor Vessel Material Surveillance." Specific recommendations for an acceptable neutron fluence monitoring AMP are provided in GALL-SLR Report AMP X.M2, "Neutron Fluence Monitoring."

Loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel beltline, lower and intermediate shells, nozzles, and welds. The neutron fluence TLAA is discussed in Section 4.2.1, *Neutron Fluence Projections* and is managed by the Neutron Fluence Monitoring (B.2.2.2) AMP. The Neutron Fluence Monitoring (B.2.2.2) AMP monitors the plant conditions to ensure the assumptions of the Neutron Fluence Projections TLAA remain bounding and is implemented in conjunction with the Reactor Vessel Material Surveillance (B.2.3.19) AMP. This AMP is consistent with 10 CFR Part 50, Appendix H.

(3) Reduction in Fracture Toughness is a plant-specific TLAA for Babcock & Wilcox (B&W) reactor internals to be evaluated for the subsequent period of extended operation in accordance with the NRC staff's safety evaluation concerning "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," B&W Owners Group report number BAW-2248, which is included in BAW-2248A, March 2000. Plant-specific TLAAs are addressed in Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR.

Not applicable. This further evaluation item is only applicable to Babcock & Wilcox reactor internals.

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

(1) Cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) could occur in stainless steel (SS) and nickel alloy reactor vessel (RV) flange leak detection lines of BWR light-water reactor facilities. The plant-specific operating experience (OE) and condition of the RV flange leak detection lines are evaluated to determine if SCC or IGSCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of SCC or IGSCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.

Although the MNGP reactor vessel flange leak-off lines are carbon steel and therefore not susceptible to cracking, other RPV and RCPB components are constructed of stainless steel. Plant-specific OE has shown that the reactor vessel and RCPB components have not been susceptible to SCC. Therefore, the One-Time Inspection (B.2.3.20) AMP will be used to verify the absence of SCC in stainless steel reactor vessel components.

(2) Cracking due to SCC and IGSCC could occur in SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on control of reactor water chemistry to mitigate SCC and on ASME Code Section XI ISI to detect cracking. However, the existing program should be augmented to detect cracking due to SCC and IGSCC. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable. MNGP does not utilize an isolation condenser.

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. For CLBs that include these types of evaluations, the evaluations may need to be identified as TLAAs if they are determined to conform to the six criteria for defining TLAAs in 10 CFR 54.3(a). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code Section XI2. See SRP-SLR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

Not applicable. This further evaluation item is applicable to PWRs only.

3.1.2.2.6 Cracking Due to Stress Corrosion Cracking

(1) Cracking due to SCC could occur in PWR SS bottom-mounted instrument guide tubes exposed to reactor coolant. Further evaluation is recommended to ensure that these aging effects are adequately managed. A plant-specific AMP should be evaluated to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable. This further evaluation item is applicable to PWRs only.

(2) Cracking due to SCC could occur in Class 1 PWR cast austenitic stainless steel (CASS) reactor coolant system piping and piping components exposed to reactor coolant. The existing program relies on control of water chemistry to mitigate SCC; however, SCC could occur in CASS components that do not

meet the NUREG–0313, "Technical Report on Material Selection and Process Guidelines for BWR Coolant Pressure Boundary Piping" guidelines with regard to ferrite and carbon content. Further evaluation is recommended of a plant-specific program for these components to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable. This further evaluation item is applicable to PWRs only.

(3) Cracking due to SCC could occur in SS or nickel alloy RV flange leak detection lines of PWR light-water reactor facilities. The plant-specific OE and condition of the RV flange leak detection lines are evaluated to determine if SCC has occurred. The aging effect of cracking in SS and nickel alloy RV flange leak detection lines is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring. The applicant documents the results of the plant-specific OE review in the SLRA. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that cracking is not occurring. If cracking has occurred, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking in RV flange leak detection lines.

Not applicable. This further evaluation item is applicable to PWRs only.

3.1.2.2.7 Cracking Due to Cyclic Loading

Cracking due to cyclic loading could occur in steel and SS BWR isolation condenser components exposed to reactor coolant. The existing program relies on ASME Code Section XI ISI. However, the existing program should be augmented to detect cracking due to cyclic loading. An augmented program is recommended to include temperature and radioactivity monitoring of the shell-side water and eddy current testing of tubes to ensure that the component's intended function will be maintained during the subsequent period of extended operation. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable. MNGP does not utilize an isolation condenser.

3.1.2.2.8 Loss of Material Due to Erosion

Loss of material due to erosion could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater. Further evaluation is recommended of a plant-specific AMP to ensure that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Not applicable. This further evaluation item is applicable to PWRs only.

3.1.2.2.9 Aging Management of PWR Reactor Vessel Internals (Applicable to Subsequent License Renewal Periods Only)

Electric Power Research Institute (EPRI) Topical Report (TR)-1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)" (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML12017A191 through ML12017A197 and ML12017A199), provided the industry's initial set of aging management inspection and evaluation (I&E) recommendations for the reactor vessel internal (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 Topical Report No. 3002017168, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A)" (ADAMS Accession No. 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 (ADAMS Accession No. ML19081A001) and approved the topical report for use as documented in the staff's letters to the EPRI Materials Reliability Program (MRP) dated February 19, 2020 and July 7, 2020 (ADAMS Accession Nos. 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: (a) stress corrosion cracking (SCC), (b) irradiation-assisted stress corrosion cracking (IASCC), (c) fatigue, (d) wear, (e) neutron irradiation embrittlement, (f) thermal aging embrittlement, (g) void swelling and irradiation growth or component distortion, and (h) 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 whether operation of Westinghouse-designed, B&W-designed and CE-designed reactors during an SLR operating period (60 to 80 years) would have any impact 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.*

Subsequent license renewal (SLR) applicants for units of a PWR design will no longer need to include separate SLRA Appendix C section responses in resolution of the 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 unnecessary.

Alternatively, the PWR SLRA may define a plant-specific AMP for the RVI components to demonstrate that the RVI components will be managed in accordance with the requirements of 10 CFR 54.21(a)(3) during the proposed subsequent period of extended operation. Components to be inspected, parameters monitored, monitoring methods, inspection sample size, frequencies, expansion criteria, and acceptance criteria are justified in the SLRA. 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 SRP-SLR Appendix A.1.

Not applicable. This further evaluation item is applicable to PWRs only.

3.1.2.2.10 Loss of Material Due to Wear

(1) Industry OE indicates that loss of material due to wear can occur in PWR control rod drive (CRD) head penetration nozzles made of nickel alloy due to the interactions between the nozzle and the thermal sleeve centering pads of the nozzle (see Ref. 29). The CRD head penetration nozzles are also called control rod drive mechanism (CRDM) nozzles or CRDM head adapter tubes. The applicant should perform a further evaluation to confirm the adequacy of a plant-specific AMP or analysis (with any necessary inspections) for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP. Alternatively, the applicant may perform an analysis with any necessary inspections to confirm

that loss of material due to wear does not affect the intended function(s) of these CRD head penetration nozzles, consistent with the current licensing basis (CLB).

Not applicable. This further evaluation item is applicable to PWRs only.

(2) Industry OE indicates that loss of material due to wear can occur in the SS thermal sleeves of PWR CRD head penetration nozzles due to the interactions between the nozzle and the thermal sleeve (e.g., where the thermal sleeve exits from the head penetration nozzle inside the reactor vessel as described in Ref. 30). Therefore, the applicant should perform a further evaluation to confirm the adequacy of a plant-specific AMP for management of the aging effect. The applicant may use the acceptance criteria, which are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR), to demonstrate the adequacy of a plant-specific AMP.

Not applicable. This further evaluation item is applicable to PWRs only.

3.1.2.2.11 Cracking Due to Primary Water Stress Corrosion Cracking

(1) Foreign OE in steam generators with a design similar to that of Westinghouse steam generators (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in steam generator (SG) divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry. Cracks have been detected in the stub runner with depths typically about 0.08 inches (EPRI 3002002850).

All but one of these instances of cracking has been detected in divider plate assemblies that are approximately 1.3 inches in thickness. For the cracks in the 1.3-inch thick divider plate assemblies, the cracks tend to be parallel to the divider-plate-to-stub-runner weld (i.e., run horizontally in parallel to the lower surface of the tubesheet). For the one instance of cracking in a divider plate assembly with a thickness greater than 1.3 inches, the cracking occurred in a divider plate assembly with a thickness of approximately 2.4 inches near manufacturing marks on the upper end of the stub runner used for locating tubesheet holes. These flaws were estimated to be approximately 0.08-inch deep.

Although these instances indicate that the water chemistry program may not be sufficient to manage cracking due to PWSCC in SG divider plate assemblies, analyses by the industry indicate that PWSCC in the divider plate assembly does not pose a structural integrity concern for other steam generator components (e.g., tubesheet and tube-to-tubesheet welds) and does not adversely affect other safety analyses (e.g., analyses supporting tube plugging and repairs, tube repair criteria, and design basis accidents). In addition, the industry analyses indicate that flaws in the divider plate assembly will not adversely affect the heat transfer function (as a result of bypass flow) during normal forced flow operation, during natural circulation conditions (assessed in the analyses of various design basis accidents), or in the event of a loss-of-coolant accident (LOCA).

Furthermore, additional industry analyses indicate that PWSCC in the divider plate assembly is unlikely to adversely impact adjacent items, such as the tubesheet cladding, tube-to-tubesheet welds, and channel head. Therefore,

- *For units with divider plate assemblies fabricated of Alloy 690 and Alloy 690 type weld materials, a plant-specific AMP is not necessary.*

- *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the analyses performed by the industry (EPRI 3002002850) are applicable and bounding for the unit, a plant-specific AMP is not necessary.*

- *For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the industry analyses (EPRI 3002002850) are not bounding for the applicant's unit, a plant-specific AMP is necessary or a rationale is necessary for why such a program is not needed. A plant-specific AMP (one beyond the primary water chemistry and the steam generator programs) may include a one-time inspection that is capable of detecting cracking to verify the effectiveness of the water chemistry and steam generator programs and the absence of PWSCC in the divider plate assemblies.*

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and general visual inspections of the channel head interior surfaces (included as part of the steam generator program). The GALL-SLR Report recommends further evaluation for a plant-specific AMP to confirm the effectiveness of the primary water chemistry and steam generator programs as described in this section. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

Not applicable. This further evaluation item is applicable to PWRs only.

(2) Cracking due to PWSCC could occur in SG nickel alloy tube-to-tubesheet welds exposed to reactor coolant. The acceptance criteria for this review are:

- *For units with Alloy 600 SG tubes for which an alternate repair criterion such as C*, F*, H*, or W* has been permanently approved for both the hot- and cold-leg side of the steam generator, the weld is no longer part of the reactor coolant pressure boundary and a plant-specific AMP is not necessary;*

- *For units with Alloy 600 steam generator tubes, if there is no permanently approved alternate repair criteria such as C*, F*, H*, or W*, or permanent approval applies to only either the hot- or cold-leg side of the steam generator, a plant-specific AMP is necessary;*

- *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 690 type material, a plant-specific AMP is not necessary;*

- *For units with thermally treated Alloy 690 SG tubes and with tubesheet cladding using Alloy 600 type material, a plant-specific AMP is necessary unless the applicant confirms that the industry's analyses for tube-to-tubesheet weld cracking (e.g., chromium content for the tube-to-tubesheet welds is approximately 22 percent and the tubesheet primary face is in compression as discussed in EPRI 3002002850) are applicable and bounding for the unit, and the applicant will perform general visual inspections of the tubesheet region looking for evidence of cracking (e.g., rust stains on the tubesheet cladding) as part of the steam generator program. In lieu of a plant-specific AMP, the applicant may provide a rationale for why a plant-specific AMP is not necessary.*

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and visual inspections of the steam generator head interior surfaces. Along with the primary water chemistry and steam generator programs, a plant-specific AMP should be evaluated to confirm the effectiveness of the primary water chemistry and steam generator programs in certain circumstances. A plant-specific AMP may include a one-time inspection that is capable of detecting cracking to confirm the absence of PWSCC in the tube-to-tubesheet welds. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

Not applicable. This further evaluation item is applicable to PWRs only.

3.1.2.2.12 Cracking Due to Irradiation-Assisted Stress Corrosion Cracking

GALL-SLR Report AMP XI.M9, "BWR Vessel Internals," manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience cracking due to IASCC. The existing Boiling Water Reactor Vessel and Internals Project (BWRVIP) examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. However, increases in neutron fluence during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage cracking due to IASCC. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant identifies the components to be inspected and performs supplemental inspections to adequately manage IASCC. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.

Cracking due to irradiation-assisted stress corrosion cracking is generically evaluated for extended operation up to 80 years and the associated increase in neutron fluence in BWRVIP-315 "Reactor Internals Aging Management Evaluation for Extended Operations" (Reference 1.6.30). This evaluation dispositions the applicable BWR vessel internals components into three potential categories:

<u>IASCC Not Applicable</u>

These components are in low fluence regions of the vessel which will remain well below the fluence screening threshold or the BWRVIP safety assessments have concluded that cracking due to any mechanism does not require aging management.

<u>IASCC Plausible but Managed by Existing Guidance</u>

This category is applicable to the core shroud beltline cylinder. While the core shroud beltline cylinder is subject to enough fluence to consider IASCC an applicable aging mechanism, BWRVIP-76, Revision 1-A provides guidance for periodic inspections for cracking, and the flaw tolerance evaluation guidelines in BWRVIP-76 consider the effects of neutron fluence such that IASCC can be appropriately managed using the existing guidance.

<u>IASCC Plausible but Can be Managed by Existing Guidance with Clarifications</u>

The component may exceed the IASCC fluence threshold during operation up to 80 years the existing guidance remains adequate provided the guidance is enhanced to clarify the methods to be used for evaluation of flaws in irradiated components.

These enhancements to existing guidance are identified in BWRVIP-315 and are identified alongside the LAIs in Appendix C. MNGP is committed to following the latest NRC-approved BWRVIP guidance and will incorporate the guidance enhancements as shown in BWRVIP-315 or the latest approved BWRVIP guidance addressing IASCC for operation to 80 years.

All components for which BWRVIP-315 identifies IASCC as a plausible aging mechanism are evaluated in TLAA Section 4.2.10, which projects the maximum fluence value for these components and demonstrates that the generic fluence assumptions in BWRVIP-315 are representative of the fluence projections for MNGP.

Based on the projected end of life (EOL) fluence, the jet pump assemblies will be inspected periodically for cracking per BWRVIP-41 Revision 4-A as modified by recommendations shown in BWRVIP-315. The core shroud will be inspected periodically for cracking per BWRVIP-76-R1A 4-A as modified by recommendations shown in BWRVIP-315. The top guide will continue to be periodically inspected for cracking per BWRVIP-26A and BWRVIP-183-A as modified by recommendations shown in BWRVIP-315.

The existing guidance implemented by the BWR Vessel Internals (B.2.3.7) AMP, including the clarifying enhancements identified in BWRVIP-315 and recognized alongside the LAIs in Appendix C, will appropriately manage IASCC in the reactor vessel internals for 80 years of operation.

As such, IASCC is managed by the BWR Vessel Internals (B.2.3.7) AMP.

3.1.2.2.13 Loss of Fracture Toughness Due to Neutron Irradiation or Thermal Aging Embrittlement

GALL-SLR Report AMP XI.M9 manages aging degradation of nickel alloy and SS, including associated welds, which are used in BWR vessel internal components. When exposed to the BWR vessel environment, these materials can experience loss of fracture toughness due to neutron irradiation embrittlement. In addition, CASS, precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel) and martensitic SS (e.g., 403, 410, 431 steel) can experience loss of fracture toughness due to neutron irradiation or thermal aging embrittlement.

The existing BWRVIP examination guidelines are mainly based on aging evaluation of BWR vessel internals for operation up to 60 years. Increases in neutron fluence and thermal embrittlement during the SLR term may need to be assessed for supplemental inspections of BWR vessel internals to adequately manage loss of fracture toughness due to neutron irradiation or thermal aging embrittlement. Therefore, the applicant should perform an evaluation to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines. If the applicant determines that supplemental inspections are not necessary, the applicant should provide adequate technical justification for the determination. If supplemental inspections are determined necessary for BWR vessel internals, the applicant should identify the components to be inspected and perform supplemental inspections to adequately manage loss of fracture toughness. In addition, the applicant should confirm the adequacy of any necessary supplemental inspections and enhancements to the BWR Vessel Internals Program.

Loss of Fracture Toughness Due to Neutron Irradiation or Thermal Aging Embrittlement is generically evaluated for extended operation up to 80 years and the associated increase in neutron fluence in BWRVIP-315 “Reactor Internals Aging Management Evaluation for Extended Operations”. The BWRVIP program provides appropriate tools for managing cracking in internals with high fluence. Since the onset of significant irradiation effects on material properties in stainless steels occurs at roughly the same fluence as the threshold for consideration of IASCC, the BWRVIP has taken a simplified approach in which these two degradation mechanisms are treated together.

All components for which BWRVIP-315 identifies IASCC as a plausible aging mechanism are evaluated in TLAA Section 4.2.10 which projects the maximum fluence value for these components and demonstrates that the generic fluence assumptions in BWRVIP-315 are representative of the fluence projections for MNGP.

Based on the projected EOL fluence, the jet pump assemblies will be inspected periodically for loss of fracture toughness per BWRVIP-41 Revision 4-A as modified by recommendations shown in BWRVIP-315. The core shroud will be inspected periodically for loss of fracture toughness per BWRVIP-76-R1A 4-A as modified by recommendations shown in BWRVIP-315. The top guide will continue to be periodically inspected for loss of fracture toughness per BWRVIP-26A and BWRVIP-183-A as modified by recommendations shown in BWRVIP-315.

The existing guidance implemented by the BWR Vessel Internals (B.2.3.7) AMP, including the clarifying enhancements identified in BWRVIP-315 and recognized alongside the LAIs in Appendix C, will appropriately manage loss of fracture toughness in the reactor vessel internals for 80 years of operation.

As such, loss of fracture toughness is managed by the BWR Vessel Internals (B.2.3.7) AMP.

3.1.2.2.14 Loss of Preload Due to Thermal or Irradiation-Enhanced Stress Relaxation

GALL-SLR Report AMP XI.M9 manages loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR core plate rim holddown bolts. The issue is applicable to BWR-designed light water reactors that employ rim holddown bolts as the means for protecting the reactor's core plate from the consequences of lateral movement. The potential for such movement, if left unmanaged, could impact the ability of the reactor to be brought to a safe shutdown condition during an anticipated transient occurrence or during a postulated design-basis accident or seismic event. This issue is not applicable to BWR reactor designs that use wedges as the means of precluding lateral movement of the core plate because the wedges are fixed in place and are not subject to this type of aging effect and mechanism combination.

GALL-SLR Report AMP XI.M9 indicates that the inspections in the BWRVIP topical report, "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines (BWRVIP-25)," are used to manage loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR designs with core plate rim holddown bolts. However, in previous license renewal applications (LRAs), some applicants have identified that the inspection bases for managing loss of preload in BWRVIP-25 may not be capable of gaining access to the rim holddown bolts or are not sufficient to detect loss of preload on the components. For applicants that have identified this issue in their past LRAs, the applicants either committed to modifying the plant design to install wedges in the core plate designs or to submit an inspection plan, with a supporting core plate rim holddown bolt preload analysis for NRC approval at least 2 years prior to entering into the initial period of extended operation for the facility.

If an existing NRC-approved analysis for the bolts exists in the CLB and conforms to the definition of a TLAA, the applicant should identify the analysis as a TLAA for the SLRA and demonstrate how the analysis is acceptable in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii). Otherwise, if a new analysis will be performed to support an updated augmented inspection basis for the bolts for the subsequent period of extended operation, the NRC staff recommends that a license renewal commitment be placed in the FSAR Supplement for the applicant to submit both the inspection plan and the supporting loss of preload analysis to the NRC staff for approval at least 2 years prior to entering into the subsequent period of extended operation for the facility. If loss of preload in the bolts is managed with an AMP that correlates to GALL-SLR Report AMP XI.M9, the inspection basis in the applicable BWRVIP report is reviewed for continued validity, or else augmented as appropriate.

Loss of preload due to thermal or irradiation-enhanced stress relaxation in core plate rim holddown bolts, as described in SRP-SLR Item 3.3.2.2.14, is addressed as a TLAA in Section 4.2.9, *Loss of Preload for Core Plate Rim Holddown Bolts*.

3.1.2.2.15 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

There are no RCS stainless steel or steel piping or piping components within the scope of SLR that are exposed to concrete at MNGP. Where RCS piping is required to penetrate concrete, penetration sleeves are used. This is addressed further in Section 3.5.

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: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and *crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.*

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping and piping components exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage loss of material due to pitting or crevice corrosion. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Ambient air at MNGP is not subject to a marine atmosphere. MNGP is located in the vicinity of a major road that is routinely salted for snow and ice. A review of the over 69,000 ARs created during the 01/01/2010 to 07/29/2021 period was performed to determine if the proximity to the salted road has resulted in any plant-specific OE for loss of material of the susceptible materials to chlorides in an air environment. The results of this review show that the ambient air environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. As such, stainless steel and nickel alloy components exposed to air indoor uncontrolled in the RCS are not susceptible to loss of material.

Plant-specific OE associated with insulated stainless steel components in the RCS has been evaluated to determine if prolonged exposure to moisture has resulted in loss of material due to pitting or crevice corrosion. Loss of material has not been identified as an aging effect at MNGP for insulated stainless steel components for 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.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that loss of material is not occurring in nickel alloy and stainless steel components exposed to an air indoor uncontrolled environment. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, corrective action program (CAP). The One-Time Inspection AMP is described in Section B.2.3.20.

3.1.2.2.17 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix A.2 of the SRP-SLR)

QA provisions applicable to SLR are discussed in Appendix B.1.3, *Quality Assurance Program and Administrative Controls*.

3.1.2.2.18 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs" in the SRP-SLR.

The OE process and acceptance criteria are described in Section B.1.4.

3.1.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Reactor Vessels, Internals, and Reactor Coolant system components:

- Section 4.2, *Reactor Vessel Neutron Embrittlement Analysis*
- Section 4.3, *Metal Fatigue*
- Section 4.7, *Other Plant-Specific TLAAs*

3.1.3 Conclusion

The Reactor Vessels, Internals, and Reactor Coolant System piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for the Reactor Vessels, Internals, and Reactor Coolant system components are identified in the summaries in Section 3.1.2 above.

A description of these AMPs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Vessels, 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 CLB during the SPEO.

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-001	Steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel reactor vessel closure studs and nuts exposed to air - indoor uncontrolled is addressed as a TLAA in Section 4.3. Further evaluation is documented in Section 3.1.2.2.1.
3.1.1-002	Not applicable. This line item only applies to PWRs.				
3.1.1-003	Stainless steel, nickel alloy reactor vessel internal components exposed to reactor coolant, neutron flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant is addressed as a TLAA in Section 4.3. Further evaluation is documented in Section 3.1.2.2.1.
3.1.1-004	Steel pressure vessel support skirt and attachment welds	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel reactor vessel components is addressed as a TLAA in Section 4.3. Further evaluation is documented in Section 3.1.2.2.1.
3.1.1-005	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-006	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor coolant pressure boundary components: piping, piping components; other pressure retaining components exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel and stainless steel RCPB components exposed to reactor coolant is addressed as a TLAA in Section 4.3. Further evaluation is documented in Section 3.1.2.2.1.
3.1.1-007	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor vessel components: nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel, steel with stainless steel cladding, stainless steel and nickel alloy reactor vessel components exposed to reactor coolant is addressed as a TLAA in Section 4.3. Further evaluation is documented in Section 3.1.2.2.1.
3.1.1-008	Not applicable. This line item only applies to PWRs.				
3.1.1-009	Not applicable. This line item only applies to PWRs.				
3.1.1-010	Not applicable. This line item only applies to PWRs.				
3.1.1-011	Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel or stainless steel Class 1 closure bolting exposed to high temperatures and thermal cycles is addressed as a TLAA in Section 4.3. Further evaluation is documented in Section 3.1.2.2.1.
3.1.1-012	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-013	Steel (with or without stainless steel or nickel alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, SRP-SLR Section 4.2 "Reactor Pressure Vessel Neutron Embrittlement"	Yes (SRP-SLR Section 3.1.2.2.3.1)	Consistent with NUREG-2191. Loss of fracture toughness due to neutron irradiation embrittlement of the steel with stainless steel cladding reactor vessel components exposed to reactor coolant and neutron flux is address by a TLAA in Section 4.2. Further evaluation is documented in Section 3.1.2.2.3.1.
3.1.1-014	Steel (with or without cladding) reactor vessel beltline shell, nozzle, and weld components; exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	AMP XI.M31, "Reactor Vessel Material Surveillance," and AMP X.M2, "Neutron Fluence Monitoring"	Yes (SRP-SLR Section 3.1.2.2.3.2)	Consistent with NUREG-2191. The Reactor Vessel Material Surveillance (B.2.3.19) and Neutron Fluence Monitoring (B.2.2.2) AMPs are used to manage loss of fracture toughness due to neutron irradiation embrittlement of the steel with stainless steel cladding reactor vessel components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.3.2.
3.1.1-015	Not applicable. This line item only applies to PWRs.				
3.1.1-016	Stainless steel or nickel alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled, reactor coolant leakage	Cracking due to SCC, IGSCC	AMP XI.M32, "One-Time Inspection," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes (SRP-SLR Section 3.1.2.2.4.1)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of stainless steel reactor vessel components exposed to air - indoor uncontrolled. Further evaluation is documented in Section 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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-017	Stainless steel isolation condenser components exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Section 3.1.2.2.4.2)	Not applicable. MNGP does not utilize an isolation condenser. Further evaluation is documented in Section 3.1.2.2.4.2.
3.1.1-018	Not applicable. This line item only applies to PWRs.				
3.1.1-019	Not applicable. This line item only applies to PWRs.				
3.1.1-020	Not applicable. This line item only applies to PWRs.				
3.1.1-021	Steel and stainless steel isolation condenser components exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	Yes (SRP-SLR Section 3.1.2.2.7)	Not applicable. MNGP does not utilize an isolation condenser. Further evaluation is documented in Section 3.1.2.2.7.
3.1.1-022	Not applicable. This line item only applies to PWRs.				
3.1.1-025	Not applicable. This line item only applies to PWRs.				
3.1.1-028	Not applicable. This line item only applies to PWRs.				
3.1.1-029	Nickel alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, irradiation- assisted SCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Section 3.1.2.2.12)	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.3.7) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of welded nickel alloy access hole covers exposed to reactor coolant. Further evaluation is documented in Section 3.1.2.2.12.

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 Program / TLAA	Further Evaluation Recommended	Discussion
3.1.1-030	Stainless steel, nickel alloy penetration: drain line exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (SCC, IGSCC mechanisms only)	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of the carbon steel with stainless steel cladding vessel shell components exposed to reactor coolant.
3.1.1-031	Steel and stainless steel isolation condenser components exposed to reactor coolant	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Not applicable. MNGP does not utilize an isolation condenser.
3.1.1-033	Not applicable. This line item only applies to PWRs.				
3.1.1-034	Not applicable. This line item only applies to PWRs.				
3.1.1-035	Not applicable. This line item only applies to PWRs.				
3.1.1-036	Not applicable. This line item only applies to PWRs.				
3.1.1-037	Not applicable. This line item only applies to PWRs.				
3.1.1-038	Cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage loss of fracture toughness of cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to reactor coolant >250 °C (482 °F).

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-039	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy Class 1 piping, fittings, and branch connections <NPS 4 exposed to reactor coolant	Cracking due to SCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), IGSCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), or thermal, mechanical, or vibratory loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," AMP XI.M2, "Water Chemistry," and XI.M35, "ASME Code Class 1 Small-Bore Piping"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1), Water Chemistry (B.2.3.2) and ASME Code Class 1 Small-Bore Piping (B.2.3.22) AMPs are used to manage cracking of steel and stainless steel piping <4" exposed to reactor coolant.
3.1.1-040	Not applicable. This line item only applies to PWRs.				
3.1.1-040a	Not applicable. This line item only applies to PWRs.				
3.1.1-041	Nickel alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Section 3.1.2.2.12)	Not applicable. The core shroud and core plate access hole cover are of welded construction and are addressed in item 3.1.1-029.
3.1.1-042	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-043	Stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) and BWR Vessel Internals (B.2.3.7) AMPs. The Water Chemistry (B.2.3.2) AMP is used to manage loss of material of stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant. However, the BWR Vessel Internals (B.2.3.7) AMP is used in lieu of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP.
3.1.1-044	Not applicable. This line item only applies to PWRs.				
3.1.1-045	Not applicable. This line item only applies to PWRs.				
3.1.1-046	Not applicable. This line item only applies to PWRs.				
3.1.1-047	Not applicable. This line item only applies to PWRs.				
3.1.1-048	Not applicable. This line item only applies to PWRs.				
3.1.1-049	Not applicable. This line item only applies to PWRs.				
3.1.1-050	Cast austenitic stainless steel Class 1 piping, piping components (including pump casings and control rod drive pressure housings) exposed to reactor coolant >250 °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.2.3.8) AMP is used to manage loss of fracture toughness of Class 1 CASS components exposed to reactor coolant >250 °C (>482 °F).
3.1.1-051a	Not applicable. This line item only applies to PWRs.				
3.1.1-051b	Not applicable. This line item only applies to PWRs.				
3.1.1-052a	Not applicable. This line item only applies to PWRs.				
3.1.1-052b	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-052c	Not applicable. This line item only applies to PWRs.				
3.1.1-053a	Not applicable. This line item only applies to PWRs.				
3.1.1-053b	Not applicable. This line item only applies to PWRs.				
3.1.1-053c	Not applicable. This line item only applies to PWRs.				
3.1.1-054	Not applicable. This line item only applies to PWRs.				
3.1.1-055a	Not applicable. This line item only applies to PWRs.				
3.1.1-055b	Not applicable. This line item only applies to PWRs.				
3.1.1-055c	Not applicable. This line item only applies to PWRs.				
3.1.1-056a	Not applicable. This line item only applies to PWRs.				
3.1.1-056b	Not applicable. This line item only applies to PWRs.				
3.1.1-056c	Not applicable. This line item only applies to PWRs.				
3.1.1-058a	Not applicable. This line item only applies to PWRs.				
3.1.1-058b	Not applicable. This line item only applies to PWRs.				
3.1.1-059a	Not applicable. This line item only applies to PWRs.				
3.1.1-059b	Not applicable. This line item only applies to PWRs.				
3.1.1-059c	Not applicable. This line item only applies to PWRs.				
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. The Flow-Accelerated Corrosion (B.2.3.9) AMP is used to manage wall thinning of steel components exposed to reactor coolant.
3.1.1-061	Not applicable. This line item only applies to PWRs.				
3.1.1-062	High-strength steel, stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage cracking of Class 1 stainless steel bolting exposed to air-indoor uncontrolled.

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-063	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of material of steel and stainless steel bolting exposed to air-indoor uncontrolled.
3.1.1-064	Not applicable. This line item only applies to PWRs.				
3.1.1-065	Not applicable. This line item only applies to PWRs.				
3.1.1-066	Not applicable. This line item only applies to PWRs.				
3.1.1-067	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of preload of steel and stainless steel closure bolting exposed to air-indoor uncontrolled.
3.1.1-068	Not applicable. This line item only applies to PWRs.				
3.1.1-069	Not applicable. This line item only applies to PWRs.				
3.1.1-070	Not applicable. This line item only applies to PWRs.				
3.1.1-071	Not applicable. This line item only applies to PWRs.				
3.1.1-072	Not applicable. This line item only applies to PWRs.				
3.1.1-073	Not applicable. This line item only applies to PWRs.				
3.1.1-074	Not applicable. This line item only applies to PWRs.				
3.1.1-075	Not applicable. This line item only applies to PWRs.				
3.1.1-076	Not applicable. This line item only applies to PWRs.				
3.1.1-077	Not applicable. This line item only applies to PWRs.				
3.1.1-078	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-079	Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel RCPB components exposed to reactor coolant.
3.1.1-080	Not applicable. This line item only applies to PWRs.				
3.1.1-081	Not applicable. This line item only applies to PWRs.				
3.1.1-082	Not applicable. This line item only applies to PWRs.				
3.1.1-083	Not applicable. This line item only applies to PWRs.				
3.1.1-084	Steel top head enclosure (without cladding): top head, top head nozzles (vent, top head spray, RCIC, spare) exposed to reactor coolant	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel nozzles and nozzle safe ends exposed to reactor coolant.
3.1.1-085	Stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel with stainless steel cladding, stainless steel, and nickel alloy components exposed to reactor coolant.
3.1.1-086	Not applicable. This line item only applies to PWRs.				
3.1.1-087	Not applicable. This line item only applies to PWRs.				
3.1.1-088	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-089	Not applicable. This line item only applies to PWRs.				
3.1.1-090	Not applicable. This line item only applies to PWRs.				
3.1.1-091	Steel (including high- strength steel) reactor vessel closure flange assembly components (including flanges, nut, studs, and washers) exposed to air-indoor uncontrolled	Cracking due to SCC; loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M3, "Reactor Head Closure Stud Bolting"	No	Consistent with NUREG-2191 with exception. The Reactor Head Closure Stud Bolting (B.2.3.3) AMP is used to manage loss of material and cracking of high-strength steel vessel head closure flange assembly components exposed to air-indoor uncontrolled.
3.1.1-092	Not applicable. This line item only applies to PWRs.				
3.1.1-093	Not applicable. This line item only applies to PWRs.				
3.1.1-094	Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M4, "BWR Vessel ID Attachment Welds," and AMP XI.M2, "Water Chemistry" (SCC, IGSCC mechanisms only)	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The BWR Vessel ID Attachment Welds (B.2.3.4) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of stainless steel vessel shell attachment welds exposed to reactor coolant.
3.1.1-095	Steel (with or without stainless steel or nickel alloy cladding) feedwater nozzles exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage cracking of steel with stainless steel cladding feedwater nozzles exposed to reactor coolant.

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-096	Steel (with or without stainless steel cladding) control rod drive return line nozzles and their nozzle- to-vessel welds exposed to reactor coolant in BWR-3, BWR-4, BWR-5, and BWR-6 designs	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Not used. Cracking of the steel with stainless steel control rod drive return lines nozzles and their nozzle to vessel welds is addressed by item 3.1.1-097.
3.1.1-097	Stainless steel and nickel alloy piping, piping components greater than or equal to 4 NPS; nozzle safe ends and associated welds; control rod drive return line nozzle cap and associated cap-to-nozzle weld or cap-to-safe end weld in BWR-3, BWR 4, BWR 5, and BWR-6 designs	Cracking due to SCC, IGSCC	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The BWR Stress Corrosion Cracking (B.2.3.5) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of steel with stainless steel cladding and stainless steel components exposed to reactor coolant.
3.1.1-098	Stainless steel, nickel alloy penetrations: instrumentation and standby liquid control exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M8, "BWR Penetrations," and AMP XI.M2, "Water Chemistry" (SCC, IGSCC mechanisms only)	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The BWR Penetrations (B.2.3.6) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of nickel allow penetrations exposed to reactor coolant.

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-099	Stainless steel (including cast austenitic stainless steel; PH martensitic stainless steel; martensitic stainless steel); nickel alloy (including X-750 alloy) reactor internal components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	AMP XI.M9, "BWR Vessel Internals"	Yes (SRP-SLR Section 3.1.2.2.13)	Consistent with NUREG-2191 with exception. The BWR Vessel Internals (B.2.3.7) AMP is used to manage loss of fracture toughness of stainless steel and nickel alloy reactor internals components exposed to reactor coolant and neutron flux.
3.1.1-100	Stainless steel reactor vessel internals components (jet pump wedge surface) exposed to reactor coolant	Loss of material due to wear	AMP XI.M9, "BWR Vessel Internals"	No	Consistent with NUREG-2191 with exception. The BWR Vessel Internals (B.2.3.7) AMP is used to manage loss of material of the stainless steel jet pump wedge surfaces exposed to reactor coolant.
3.1.1-101	Stainless steel steam dryers exposed to reactor coolant	Cracking due to flow- induced vibration, SCC, IGSCC; loss of material due to wear	AMP XI.M9, "BWR Vessel Internals"	No	Consistent with NUREG-2191 with exception. The BWR Vessel Internals (B.2.3.7) AMP is used to manage cracking and loss of material of the stainless steel steam dryers exposed to reactor coolant.

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-102	Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.3.7) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of stainless steel fuel support, control rod drive assemblies, and control rod drive housings exposed to reactor coolant.
3.1.1-103	Stainless steel, nickel alloy reactor internal components exposed to reactor coolant and neutron flux	Cracking due to SCC, IGSCC, IASCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	Yes (SRP-SLR Section 3.1.2.2.12)	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals (B.2.3.7) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of stainless steel and nickel alloy components exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.12.
3.1.1-104	Nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux	Cracking due to IGSCC	AMP XI.M9, "BWR Vessel Internals," and AMP XI.M2, "Water Chemistry"	No	Not used. Cracking of nickel alloy reactor vessel internal components is addressed by item 3.1.1-103.
3.1.1-105	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no MNGP RCS piping or piping components exposed to concrete. Further evaluation is documented in Section 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 Program / TLAA**	**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 components exposed to air with borated water leakage.
3.1.1-107	Stainless steel piping, piping components exposed to gas, air with borated water leakage	None	None	No	Not applicable. There are no stainless steel components exposed to gas or air with borated water leakage in the Reactor Vessels, Internals, and Reactor Coolant System.
3.1.1-110	Metallic piping, piping components exposed to reactor coolant	Wall thinning due to erosion	AMP XI.M17, "Flow- Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.3.9) AMP is used to manage wall thinning for metallic piping and piping components exposed to reactor coolant.
3.1.1-111	Not applicable. This line item only applies to PWRs.				
3.1.1-113	Steel reactor vessel external attachments exposed to indoor, uncontrolled air	Loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage loss of material of steel reactor vessel external attachments exposed to air-indoor uncontrolled.

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-114	Reactor coolant system components defined as ASME Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components, reactor vessel interior attachments, or core support structure components; or ASME Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes)	Cracking due to SCC, IGSCC, PWSCC, IASCC (SCC mechanisms for stainless steel, nickel alloy components only), fatigue, or cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, or wear	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (water chemistry- related or corrosion- related aging effect mechanisms only)	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of stainless steel components exposed to reactor coolant or treated water >60°C (>140°F).
3.1.1-115	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Not applicable. There are no MNGP stainless steel RCS piping or piping components exposed to concrete. Further evaluation is documented in Section 3.1.2.2.15.
3.1.1-116	Not applicable. This line item only applies to PWRs.				
3.1.1-117	Not applicable. This line item only applies to PWRs.				
3.1.1-118	Not applicable. This line item only applies to PWRs.				
3.1.1-119	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-120	Stainless steel core plate rim holddown bolts exposed to reactor coolant and neutron flux	Loss of preload due to thermal or irradiation- enhanced stress relaxation	AMP XI.M9, "BWR Vessel Internals," and TLAA SRP-SLR 4.7 "Other Plant-Specific TLAAs" [if an analysis is performed as part of the aging management basis and conforms to the definition of a TLAA in 10 CFR 54.3(a)]	Yes (SRP-SLR Section 3.1.2.2.14)	Consistent with NUREG-2191 with exception. The BWR Vessel Internals (B.2.3.7) AMP and TLAA Section 4.2.9 are used to loss of preload for the stainless steel core plate bolting exposed to reactor coolant and neutron flux. Further evaluation is documented in Section 3.1.2.2.14.
3.1.1-121	Stainless steel jet pump assembly holddown beam bolts exposed to reactor coolant and neutron flux	Loss of preload due to thermal or irradiation- enhanced stress relaxation	AMP XI.M9, "BWR Vessel Internals"	No	Consistent with NUREG-2191 with exception. The BWR Vessel Internals (B.2.3.7) AMP is used to manage loss of preload of nickel alloy jet pump assembly holddown beam bolts exposed to reactor coolant and neutron flux.
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.2.3.23) AMP is used to manage loss of material of steel piping and piping components exposed to air-indoor uncontrolled.
3.1.1-125	Not applicable. This line item only applies to PWRs.				
3.1.1-127	Not applicable. This line item only applies to PWRs.				

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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.1.1-128	Stainless steel, nickel alloy nozzles safe ends and welds: high pressure core spray; low pressure core spray; recirculating water, low pressure coolant injection or RHR injection mode exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The BWR Stress Corrosion Cracking (B.2.3.5) and Water Chemistry (B.2.3.2) AMPs are used to manage cracking of stainless steel components exposed to reactor coolant.
3.1.1-129	Steel and stainless steel piping, piping components exposed to reactor coolant: welded connections between the re-routed control rod drive return line and the inlet piping system that delivers return line flow to the reactor pressure vessel exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP is used to manage cracking of the steel control rod drive return line welded connection exposed to reactor coolant.
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. The One-Time Inspection (B.2.3.20) AMP is used to manage long-term loss of material of steel components exposed to treated water and reactor coolant.
3.1.1-134	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. Non-metallic thermal insulation associated with reactor coolant piping and piping components does not perform a SLR intended function and is therefore not in scope.

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 Program / TLAA	Further Evaluation Recommended	Discussion
3.1.1-136	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.1.2.2.16)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of nickel alloy and stainless steel components exposed to air indoor uncontrolled. Further evaluation is documented in Section 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 with 15% zinc or less piping or piping components in the MNGP RCS. Cracking in copper alloy >15% Zinc (Zn) exposed to air indoor uncontrolled is addressed in item 3.4.1-106.
3.1.1-139	Not applicable. This line item only applies to PWRs.				

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bottom Head	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.2.3.23)	IV.C1.R-431	3.1.1-124	C
Bottom Head	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.2.3.1)	IV.A1.RP-371	3.1.1-030	C
Bottom Head	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.RP-371	3.1.1-030	D
Bottom Head	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage Cracking	TLAA – Section 4.3, Metal Fatigue	IV.A1.R-04	3.1.1-007	A
Bottom Head	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Bottom Head	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Control Rod Drive Return Line Nozzle	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.2.3.23)	IV.C1.R-431	3.1.1-124	A
Control Rod Drive Return Line Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.A1.R-412	3.1.1-097	A

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Control Rod Drive Return Line Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.R-412	3.1.1-097	B
Control Rod Drive Return Line Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Control Rod Drive Return Line Nozzle	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Head Spray Cap	Pressure Boundary	Stainless steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	IV.A1.R-61a	3.1.1-016	C
Head Spray Cap	Pressure Boundary	Stainless steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Head Spray Cap	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.A1.R-412	3.1.1-097	C
Head Spray Cap	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.R-412	3.1.1-097	D
Head Spray Cap	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Head Spray Cap	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Nozzle Safe Ends	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Nozzle Safe Ends	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1.1-084	C

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Nozzle Safe Ends	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-50	3.1.1-084	D
Nozzle Safe Ends And Flanges	Pressure Boundary	Stainless steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	IV.A1.R-61a	3.1.1-016	C
Nozzle Safe Ends And Flanges	Pressure Boundary	Stainless steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Nozzle Safe Ends And Flanges	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.A1.R-68	3.1.1-128	C
Nozzle Safe Ends And Flanges	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1.1-128	D
Nozzle Safe Ends And Flanges	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Nozzle Safe Ends And Flanges	Pressure Boundary	Stainless steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Nozzles	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.2.3.23)	IV.C1.R-431	3.1.1-124	A
Nozzles	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.A1.R-68	3.1.1-128	C
Nozzles	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1.1-128	D
Nozzles	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzles	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Nozzles	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Nozzles	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.R-448	3.1.1-133	A
Nozzles	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-50	3.1.1-084	A
Nozzles	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-50	3.1.1-084	B
Nozzles: Feedwater	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.2.3.23)	IV.C1.R-431	3.1.1-124	A
Nozzles: Feedwater	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.2.3.1)	IV.A1.R-65	3.1.1-095	A
Nozzles: Feedwater	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.A1.R-68	3.1.1-128	C
Nozzles: Feedwater	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1.1-128	D

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzles: Feedwater	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Nozzles: Feedwater	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Reactor Vessel Components with Fatigue Analysis	Pressure Boundary	Carbon Steel Nickel Alloy Stainless Steel Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage Cracking	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-04	3.1.1-007	A
Reactor Vessel Shells, Nozzles, And Welds in the Beltline Region of the Reactor Vessel	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of Fracture Toughness	Neutron Fluence Monitoring (B.2.2.2)	IV.A1.RP-227	3.1.1-014	A
Reactor Vessel Shells, Nozzles, And Welds in the Beltline Region of the Reactor Vessel	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of Fracture Toughness	Reactor Vessel Material Surveillance (B.2.3.19)	IV.A1.RP-227	3.1.1-014	A
Reactor Vessel Shells, Nozzles, And Welds in the Beltline Region of the Reactor Vessel	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of Fracture Toughness	TLAA - Section 4.2, Reactor Vessel Neutron Embrittlement	IV.A1.R-62	3.1.1-013	A
Support Skirt and Attachment Welds	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage Cracking	TLAA - Section 4.3, Metal Fatigue	IV.A1.R-70	3.1.1-004	A

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Support Skirt and Attachment Welds	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.A1.R-409	3.1.1-113	A
Support Skirt and Attachment Welds	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.T-24	3.5.1-091	A
Top Head Instrument Nozzle Flange	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	IV.A1.R-61a	3.1.1-016	C
Top Head Instrument Nozzle Flange	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Top Head Instrument Nozzle Flange	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.A1.R-68	3.1.1-128	A
Top Head Instrument Nozzle Flange	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.R-68	3.1.1-128	B
Top Head Instrument Nozzle Flange	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Top Head Instrument Nozzle Flange	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Top Head	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.2.3.23)	IV.C1.R-431	3.1.1-124	A

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Top Head	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.2.3.1)	IV.A1.RP-371	3.1.1-030	C
Top Head	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.RP-371	3.1.1-030	D
Top Head	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Top Head	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Vessel Head Closure Studs and Nuts	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.2.3.3)	IV.A1.RP-51	3.1.1-091	B
Vessel Head Closure Studs and Nuts	Mechanical Closure	High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater	Air - Indoor Uncontrolled (External)	Cumulative Fatigue Damage Cracking	TLAA - Section 4.3, Metal Fatigue	IV.A1.RP-201	3.1.1-001	A
Vessel Head Closure Studs and Nuts	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.2.3.3)	IV.A1.RP-165	3.1.1-091	B

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Vessel Penetrations	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Vessel Penetrations	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	BWR Penetrations (B.2.3.6)	IV.A1.RP-369	3.1.1-098	A
Vessel Penetrations	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.RP-369	3.1.1-098	B
Vessel Penetrations	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Vessel Penetrations	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B
Vessel Shell and Welds	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.2.3.23)	IV.C1.R-431	3.1.1-124	A
Vessel Shell and Welds	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.2.3.1)	IV.A1.RP-371	3.1.1-030	C
Vessel Shell and Welds	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.RP-371	3.1.1-030	D
Vessel Shell and Welds	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Vessel Shell and Welds	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B

Table 3.1.2-1: Reactor Pressure Vessel – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Vessel Shell Attachment Welds	Structural Support	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Vessel ID Attachment Welds (B.2.3.4)	IV.A1.R-64	3.1.1-094	A
Vessel Shell Attachment Welds	Structural Support	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.A1.R-64	3.1.1-094	B
Vessel Shell Attachment Welds	Structural Support	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.A1.RP-157	3.1.1-085	A
Vessel Shell Attachment Welds	Structural Support	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.A1.RP-157	3.1.1-085	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Access Hole Covers (Welded)	Direct Flow	Nickel Alloy	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-94	3.1.1-029	B
Access Hole Covers (Welded)	Direct Flow	Nickel Alloy	Reactor Coolant	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-94	3.1.1-029	B
Control Rod Drive Housing	Structural Support	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-104	3.1.1-102	B
Control Rod Drive Housing	Structural Support	Stainless Steel	Reactor Coolant	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1.1-102	B
Control Rod Guide Tube and Base	Structural Support	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-104	3.1.1-102	B
Control Rod Guide Tube and Base	Structural Support	Stainless Steel	Reactor Coolant	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1.1-102	B
Control Rod Guide Tube Base	Structural Support	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.R-416	3.1.1-099	B
Core Plate and Core Plate Bolts	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-93	3.1.1-103	B
Core Plate and Core Plate Bolts	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-93	3.1.1-103	B
Core Plate and Core Plate Bolts	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Core Plate and Core Plate Bolts	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Preload	BWR Vessel Internals (B.2.3.7)	IV.B1.R-420	3.1.1-120	B
Core Plate and Core Plate Bolts	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Preload	TLAA - Section 4.2.9, Loss of Preload	IV.B1.R-420	3.1.1-120	E, 1
Core Shroud (Upper, Central, Lower)	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-92	3.1.1-103	B
Core Shroud (Upper, Central, Lower)	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-92	3.1.1-103	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Core Shroud (Upper, Central, Lower)	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Core Shroud (Upper, Central, Lower)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-92	3.1.1-103	B
Core Shroud (Upper, Central, Lower)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-92	3.1.1-103	B
Core Shroud (Upper, Central, Lower)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Core Spray Lines and Spargers; Headers, Spray Rings, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-99	3.1.1-103	B
Core Spray Lines and Spargers; Headers, Spray Rings, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1.1-103	B
Core Spray Lines and Spargers; Headers, Spray Rings, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Core Spray Lines and Spargers; Spray Nozzles	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-99	3.1.1-103	B
Core Spray Lines and Spargers; Spray Nozzles	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1.1-103	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Core Spray Lines and Spargers; Spray Nozzles	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Core Spray Lines and Spargers; Piping Supports, Clamp Modification	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-99	3.1.1-103	B
Core Spray Lines and Spargers; Piping Supports, Clamp Modification	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1.1-103	B
Core Spray Lines and Spargers; Piping Supports, Clamp Modification	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Intermediate Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, Incore Flux Monitor Dry Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-105	3.1.1-103	B
Intermediate Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, Incore Flux Monitor Dry Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-105	3.1.1-103	B
Intermediate Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, Incore Flux Monitor Dry Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Jet Pump Assembly Castings; Elbow, Collar, Flare, Flange, Transition Piece	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-219	3.1.1-099	B
Jet Pump Assembly; Holddown Beam Bolts	Mechanical Closure	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Preload	BWR Vessel Internals (B.2.3.7)	IV.B1.R-421	3.1.1-121	B
Jet Pump Assembly; Holddown Beam Bolts	Mechanical Closure	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Holddown Beam Bolts	Mechanical Closure	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Holddown Beam Bolts	Mechanical Closure	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Jet Pump Assembly; Holddown Beams	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Holddown Beams	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Holddown Beams	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Jet Pump Assembly; Riser Brace Arm	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Riser Brace Arm	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Riser Brace Arm	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Jet Pump Assembly; Riser Pipe, Diffuser, Inlet Elbow, Inlet Header, Mixing Assembly, Thermal Sleeve, Elbow, Collar, Flare, Flange, Transition Piece	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Riser Pipe, Diffuser, Inlet Elbow, Inlet Header, Mixing Assembly, Thermal Sleeve, Elbow, Collar, Flare, Flange, Transition Piece	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-100	3.1.1-103	B
Jet Pump Assembly; Riser Pipe, Diffuser, Inlet Elbow, Inlet Header, Mixing Assembly, Thermal Sleeve, Elbow, Collar, Flare, Flange, Transition Piece	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Jet Pump Wedge Surfaces	Structural Support	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-377	3.1.1-100	B
Low Power Range Monitor Dry Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-105	3.1.1-103	B
Low Power Range Monitor Dry Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-105	3.1.1-103	B
Low Power Range Monitor Dry Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orificed Fuel Support	Structural Support	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-104	3.1.1-102	D
Orificed Fuel Support	Structural Support	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1.1-102	D
Orificed Fuel Support	Structural Support	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-220	3.1.1-099	B
Orificed Fuel Support	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-104	3.1.1-102	D
Orificed Fuel Support	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-104	3.1.1-102	D
Orificed Fuel Support	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-220	3.1.1-099	B
Reactor Vessel Internals Components	Direct Flow	Nickel Alloy	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Direct Flow	Nickel Alloy	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Direct Flow	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reactor Vessel Internals Components	Direct Flow	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Mechanical Closure	Nickel Alloy	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Mechanical Closure	Nickel Alloy	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Mechanical Closure	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Mechanical Closure	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Pressure Boundary	Nickel Alloy	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Pressure Boundary	Nickel Alloy	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Pressure Boundary	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Pressure Boundary	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Spray	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Spray	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Reactor Vessel Internals Components	Structural Support	Nickel Alloy	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Structural Support	Nickel Alloy	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Structural Support	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Structural Support	Stainless Steel	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-26	3.1.1-043	E, 2
Reactor Vessel Internals Components	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant	Loss of Material	Water Chemistry (B.2.3.2)	IV.B1.RP-26	3.1.1-043	B
Reactor Vessel Internals Components Subject to Fatigue	Direct Flow	Stainless Steel Nickel Alloy	Reactor Coolant	Cumulative Fatigue Damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1.1-003	A
Reactor Vessel Internals Components Subject to Fatigue	Mechanical Closure	Stainless Steel Nickel Alloy	Reactor Coolant	Cumulative Fatigue Damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1.1-003	A
Reactor Vessel Internals Components Subject to Fatigue	Pressure Boundary	Stainless Steel Nickel Alloy	Reactor Coolant	Cumulative Fatigue Damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1.1-003	A

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reactor Vessel Internals Components Subject to Fatigue	Spray	Stainless Steel	Reactor Coolant	Cumulative Fatigue Damage	TLAA -, Section 4.3, Metal Fatigue	IV.B1.R-53	3.1.1-003	A
Reactor Vessel Internals Components Subject to Fatigue	Structural Support	Stainless Steel Nickel Alloy	Reactor Coolant	Cumulative Fatigue Damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1.1-003	A
Reactor Vessel Internals Components Subject to Fatigue	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant	Cumulative Fatigue Damage	TLAA - Section 4.3, Metal Fatigue	IV.B1.R-53	3.1.1-003	A
Shroud Support Structure; Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-96	3.1.1-103	B
Shroud Support Structure; Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-96	3.1.1-103	B
Shroud Support Structure; Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Shroud Support Structure; Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-96	3.1.1-103	B
Shroud Support Structure; Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-96	3.1.1-103	B
Shroud Support Structure; Shroud Support Cylinder, Shroud Support Plate, Shroud Support Legs	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Standby Liquid Control Distribution Pipe	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-99	3.1.1-103	D
Standby Liquid Control Distribution Pipe	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1.1-103	D
Standby Liquid Control Distribution Pipe	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Standby Liquid Control Distribution Pipe	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-99	3.1.1-103	D
Standby Liquid Control Distribution Pipe	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-99	3.1.1-103	D

Table 3.1.2-2: Reactor Vessel Internals – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Standby Liquid Control Distribution Pipe	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Steam Dryer	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-155	3.1.1-101	B
Steam Dryer	Structural Integrity (Attached)	Stainless Steel	Reactor Coolant	Loss of Material	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-155	3.1.1-101	B
Top Guide	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-98	3.1.1-103	B
Top Guide	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-98	3.1.1-103	B
Top Guide	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B
Top Guide	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	BWR Vessel Internals (B.2.3.7)	IV.B1.R-98	3.1.1-103	B
Top Guide	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking	Water Chemistry (B.2.3.2)	IV.B1.R-98	3.1.1-103	B
Top Guide	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Fracture Toughness	BWR Vessel Internals (B.2.3.7)	IV.B1.RP-200	3.1.1-099	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. Loss of preload due to thermal or irradiation-enhanced stress relaxation in the core plate rim holddown bolts is addressed through the Loss of Preload for Core Rim Holddown Bolts TLAA in Section 4.2.9.

2. The BWR Vessel Internals (B.2.3.7) AMP is being substituted for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) program to manage the aging effects applicable to this component type, material, and environment combination.

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator (Steam SRV)	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	C
Accumulator (Steam SRV)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	IV.A1.R-61a	3.1.1-016	C
Accumulator (Steam SRV)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Bolting (Class 1)	Mechanical Closure	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	IV.C1.RP-42	3.1.1-063	A
Bolting (Class 1)	Mechanical Closure	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	IV.C1.RP-43	3.1.1-067	A
Bolting (Class 1)	Mechanical Closure	Carbon Steel	Air - Indoor Uncontrolled <550°F (External)	Cumulative Fatigue Damage	TLAA -Section 4.3, Metal Fatigue	IV.C1.RP-44	3.1.1-011	A
Bolting (Class 1)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	IV.C1.R-11	3.1.1-062	A
Bolting (Class 1)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	IV.C1.RP-42	3.1.1-063	A
Bolting (Class 1)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	IV.C1.RP-43	3.1.1-067	A
Bolting (Class 1)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled <550°F (External)	Cumulative Fatigue Damage	TLAA -Section 4.3, Metal Fatigue	IV.C1.RP-44	3.1.1-011	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	IV.C1.RP-42	3.1.1-063	A
Bolting (Closure)	Mechanical Closure	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	IV.C1.RP-43	3.1.1-067	A
Bolting (Closure)	Mechanical Closure	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	IV.C1.R-11	3.1.1-062	A
Bolting (Closure)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	IV.C1.RP-42	3.1.1-063	A
Bolting (Closure)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	IV.C1.RP-43	3.1.1-067	A
CRD Return Line Welded Connection	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C1.R-432	3.1.1-129	A
Heat Exchanger (Recirculating Pump Seal Cooler) Tube	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-93	3.2.1-031	A
Heat Exchanger (Recirculating Pump Seal Cooler) Tube	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Heat Exchanger (Recirculating Pump Seal Cooler) Tube	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger (Recirculating Pump Seal Cooler) Tube	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2.1-114	A
Heat Exchanger (Recirculating Pump Seal Cooler) Tube	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	V.D2.E-457	3.2.1-114	B
Orifice	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Orifice	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Orifice	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Orifice	Throttle	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Orifice	Throttle	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-71	3.4.1-014	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-71	3.4.1-014	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1.1-060	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1.1-110	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-138	3.3.1-100	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-138	3.3.1-100	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.E.R-444	3.1.1-114	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.E.R-444	3.1.1-114	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-71	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-71	3.4.1-014	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1.1-060	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1.1-110	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D1.EP-80	3.2.1-050	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D1.EP-80	3.2.1-050	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1.1-060	A
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1.1-110	A
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.C1.R-20	3.1.1-097	A
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1.1-097	B
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1.1-079	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and Piping Components Greater Than or Equal to 4" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.C1.RP-158	3.1.1-079	B
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.3.22)	IV.C1.RP-230	3.1.1-039	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C1.RP-230	3.1.1-039	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.C1.RP-230	3.1.1-039	B
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1.1-060	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1.1-110	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Code Class 1 Small-Bore Piping (B.2.3.22)	IV.C1.RP-230	3.1.1-039	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C1.RP-230	3.1.1-039	A
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.C1.RP-230	3.1.1-039	B
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1.1-079	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping and Piping Components Less Than 4" NPS and Greater Than or Equal to 1" NPS (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.C1.RP-158	3.1.1-079	B
Pump Casing (Recirculation)	Pressure Boundary	Cast Austenitic Stainless Steel	Reactor Coolant >482°F (Internal)	Loss of Fracture Toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.3.8)	IV.C1.R-52	3.1.1-050	A
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.E.R-444	3.1.1-114	A
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.C1.R-20	3.1.1-097	A
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1.1-097	B
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.E.R-444	3.1.1-114	B
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1.1-079	A
Pump Casing (Recirculation)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.C1.RP-158	3.1.1-079	B

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Reactor Coolant Pressure Boundary Components Subject to Fatigue	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA -Section 4.3, Metal Fatigue	IV.C1.R-220	3.1.1-006	A
Reactor Coolant Pressure Boundary Components Subject to Fatigue	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA -Section 4.3, Metal Fatigue	IV.C1.R-220	3.1.1-006	A
Tanks (T-208A/B)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	C
Tanks (T-208A/B)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	C
Tanks (T-208A/B)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	C
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Valve Body	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-71	3.4.1-014	A
Valve Body	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-71	3.4.1-014	B

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1.1-060	A
Valve Body	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1.1-110	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-114	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-138	3.3.1-100	A
Valve Body	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-138	3.3.1-100	A
Valve Body	Pressure Boundary	Stainless Steel	Treated water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Pressure Boundary	Stainless Steel	Treated water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1.1-060	A
Valve Body (Class 1)	Pressure Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1.1-110	A
Valve Body (Class 1)	Pressure Boundary	Cast Austenitic Stainless Steel	Reactor Coolant >482°F (Internal)	Loss of Fracture Toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.C1.R-08	3.1.1-038	A
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-452a	3.1.1-136	A
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)	IV.E.R-444	3.1.1-114	A

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	BWR Stress Corrosion Cracking (B.2.3.5)	IV.C1.R-20	3.1.1-097	A
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.C1.R-20	3.1.1-097	B
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking	Water Chemistry (B.2.3.2)	IV.E.R-444	3.1.1-114	B
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.RP-158	3.1.1-079	A
Valve Body (Class 1)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	IV.C1.RP-158	3.1.1-079	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	IV.C1.R-431	3.1.1-124	A
Valve Body	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Valve Body	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Valve Body	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-71	3.4.1-014	A
Valve Body	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-71	3.4.1-014	B

Table 3.1.2-3: Reactor Coolant Pressure Boundary and Connected Piping – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-23	3.1.1-060	A
Valve Body	Leakage Boundary	Carbon Steel	Reactor Coolant (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	IV.C1.R-406	3.1.1-110	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	IV.C1.R-448	3.1.1-133	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Note

None.

3.2 AGING MANAGEMENT OF ENGINEERED SAFETY FEATURES

3.2.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.3.2, *Engineered Safety Features*, as being subject to AMR. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Core Spray (2.3.2.1)
- High Pressure Coolant Injection (2.3.2.2)
- Primary Containment Mechanical (2.3.2.3)
- Reactor Core Isolation Cooling (2.3.2.4)
- Residual Heat Removal (2.3.2.5)
- Secondary Containment (2.3.2.6)

3.2.2 Results

Table 3.2.2-1, Core Spray – Summary of Aging Management Evaluation

Table 3.2.2-2, High Pressure Coolant Injection – Summary of Aging Management Evaluation

Table 3.2.2-3, Primary Containment Mechanical – Summary of Aging Management Evaluation

Table 3.2.2-4, Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Table 3.2.2-5, Residual Heat Removal – Summary of Aging Management Evaluation

Table 3.2.2-6, Secondary Containment – Summary of Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Core Spray

Materials

The materials of construction for the CSP System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Stainless Steel
- Stainless Steel Bolting

Environment

The CSP System components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Lubricating Oil
- Raw Water
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the CSP System require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the CSP System components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Water Chemistry (B.2.3.2)

3.2.2.1.2 High Pressure Coolant Injection

Materials

The materials of construction for the HPCI System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Fiberglass
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environment

The HPCI System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled

- Condensation
- Lubricating Oil
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the HPCI System require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduced Thermal Insulation Resistance
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the HPCI System components:

- Bolting Integrity (B.2.3.10)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.2.2.1.3 Primary Containment Mechanical

Materials

The materials of construction for the PCM System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with 15% Zinc or Less
- Nickel Alloy
- Stainless Steel
- Stainless Steel Bolting

Environment

The PCM System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Condensation
- Gas
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the PCM System require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the PCM System components:

- Bolting Integrity (B.2.3.10)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.2.2.1.4 Reactor Core Isolation Cooling

Materials

The materials of construction for the RCIC System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environment

The RCIC System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Condensation
- Lubricating Oil
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the RCIC System require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the RCIC System components:

- Bolting Integrity (B.2.3.10)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.2.2.1.5 Residual Heat Removal

Materials

The materials of construction for the RHR System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Carbon and Low Alloy Steel with Stainless Steel Cladding
- Cast Austenitic Stainless Steel
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc

- Fiberglass
- Stainless Steel
- Stainless Steel Bolting

Environment

The RHR System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Closed-Cycle Cooling Water
- Condensation
- Lubricating Oil
- Raw Water
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the RHR System require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduced Thermal Insulation Resistance
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the RHR System components:

- Bolting Integrity (B.2.3.10)
- Closed Treated Water Systems (B.2.3.12)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Water Chemistry (B.2.3.2)

3.2.2.1.6 Secondary Containment

Materials

The materials of construction for the SCT System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with 15% Zinc or Less Bolting
- Elastomer
- Galvanized Steel
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environment

The SCT System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Condensation
- Soil
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the SCT System require management:

- Cracking
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the SCT System components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

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 SLRA. For the ESF, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

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.*

Cumulative fatigue damage of ESF components, as described in SRP-SLR Item 3.2.2.2.1, is addressed in Section 4.3, *Metal Fatigue*.

Identification of components subject to this aging effect are addressed in Section 4.3 only and not in AMR Tables 3.2.2-X because all ESF Systems components have been dispositioned as 10 CFR 54.21(c)(1)(i) and do not require aging management.

3.2.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

> *Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor stainless steel (SS) and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.*
>
> *Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.*
>
> *Plant-specific operating experience (OE) and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not*

reveal a history of loss of material due to pitting or crevice corrosion, and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the SPEO. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of systems, structures, and components (SSCs), the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, a one-time inspection would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Ambient air at MNGP is not subject to a marine atmosphere. MNGP is located in the vicinity of a major road that is routinely salted for snow and ice. A review of the over 69,000 ARs created during the 01/01/2010 to 07/29/2021 period was performed to determine if the proximity to the salted road has resulted in any plant-specific OE for loss of material of the susceptible materials to chlorides in an air environment. The results of this review show that the ambient air environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. As such, stainless steel and nickel alloy components exposed to air indoor uncontrolled, air outdoor, or condensation in the ESF are not susceptible to loss of material.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that loss of material is not occurring in stainless steel or nickel alloy components exposed to air indoor uncontrolled, air outdoor, or condensation, and, in insulated stainless steel components exposed to condensation. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.2.2.2.3 Loss of Material Due to General Corrosion and Flow Blockage Due to Fouling

Loss of material due to general corrosion (as applicable) and flow blockage due to fouling for all materials can occur in the spray nozzles and flow orifices in the drywell and suppression chamber spray system exposed to air-indoor uncontrolled. This aging effect and mechanism will apply since the carbon steel piping upstream of the spray nozzles and flow orifices is occasionally wetted, even though the majority of the time this system is in standby. The wetting and drying of these components can accelerate corrosion in the system and lead to flow blockage from an accumulation of corrosion products. Aging effects sufficient to result in a loss of intended function are not anticipated if: (a) the applicant identifies those portions of the system that are normally dry but subject to periodic wetting; (b) plant-specific procedures exist to drain the normally dry portions that have been wetted during normal plant operation or inadvertently; (c) the plant-specific configuration of the drains and piping allow sufficient draining to empty the normally dry pipe; (d) plant-specific OE has not revealed loss of material or flow blockage due to fouling; and (e) a one-time inspection is conducted to verify that loss of material or flow blockage due to fouling has not occurred. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to conduct the one-time inspections. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage loss of material due to general corrosion and flow blockage due to fouling when the above conditions are not met.

This item evaluates loss of material and flow blockage of metallic drywell and suppression chamber spray nozzles exposed to condensation. The drywell and suppression chamber spray nozzles within the RHR are copper alloy with greater than 15 percent zinc and are exposed to a condensation internal environment. The RHR 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. Loss of material is not an aging effect for copper alloys in a condensation environment. 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 inservice 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 inservice 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 suppression chamber spray inboard and outboard primary containment isolation valves is filled with water to support inservice 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.

Plant-specific OE has not revealed loss of material or flow blockage of drywell or suppression chamber spray nozzles. Additionally, a verification that each drywell spray nozzle is unobstructed is performed following maintenance that could result in nozzle blockage to satisfy Technical Specification surveillance requirements. Therefore, the One-Time Inspection AMP will be implemented to manage the aging effect of flow blockage for the drywell and suppression chamber spray nozzles. Deficiencies will be documented in accordance with the site’s 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.2.2.2.4 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground *environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Ambient air at MNGP is not subject to a marine atmosphere. MNGP is located in the vicinity of a major road that is routinely salted for snow and ice. A review of the over 69,000 ARs created during the 01/01/2010 to 07/29/2021 period was performed to determine if the proximity to the salted road has resulted in any plant-specific OE for cracking of the susceptible materials to chlorides in an air environment. The results of this review show that the ambient air environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. As such, stainless steel components exposed to air indoor uncontrolled, air outdoor, or condensation in the ESF are not susceptible to cracking due to SCC.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that cracking is not occurring in stainless steel components exposed to air indoor uncontrolled, air outdoor, or condensation, and, in insulated stainless steel components exposed to condensation. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2 of this SRP-SLR).

QA provisions applicable to SLR are discussed in Section B.1.3.

3.2.2.2.6 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The OE process and acceptance criteria are described in 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 (a) a 10-year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5-year search of plant-specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the

AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the SPEO. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

MNGP OE over the past 10 years shows no instances that meet the criteria of recurring internal corrosion for metals containing raw water, waste water, or treated water in the ESF Systems; therefore, recurring internal corrosion is not an applicable aging effect at MNGP. There is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP due to recurring internal corrosion.

3.2.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of subsequent license renewal (SLR), acceptance criteria for this further evaluation are being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

<u>Susceptible Material</u>: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers *have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.*

<u>Aggressive Environment</u>: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks, which are buried or underground. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Not applicable. There are no aluminum components in the ESF Systems.

3.2.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice or pitting corrosion and cracking due to SCC (SS only) are identified as applicable aging effects. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

Not applicable. There are no steel or stainless steel piping or piping components exposed to concrete in the ESF Systems.

3.2.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other

AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Not applicable. There are no aluminum components in the ESF Systems.

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Engineered Safety Feature components:

- Section 4.3, *Metal Fatigue*

3.2.3 Conclusion

The ESF piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for the ESF System components are identified in the summaries in Section 3.2.2 above.

A description of these AMPs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Engineered Safety Feature components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-001	Stainless steel, steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes (SRP-SLR Section 3.2.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel piping and piping components is an aging effect assessed by a fatigue TLAA in Section 4.3. Identification of components subject to this aging effect are addressed in Section 4.3 only and not in AMR Tables 3.2.2-X because all ESF Systems components have been dispositioned as 10 CFR 54.21(c)(1)(i) and do not require aging management. Further evaluation is documented in Section 3.2.2.2.1.
3.2.1-004	Stainless steel, nickel alloy piping, piping components exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. This line is also used for heat exchanger components. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel and nickel alloy piping, piping components, and heat exchanger components exposed to air indoor uncontrolled, air outdoor, or condensation. Further evaluation is documented in Section 3.2.2.2.2. This line is also used for the HTV System components in the Auxiliary Systems and components in the Reactor Vessels, Internals, and Reactor Coolant System.
3.2.1-005	Not applicable. This line item only applies to PWRs.				

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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. The One-Time Inspection (B.2.3.20) AMP is used to manage flow blockage of copper alloy >15% Zn spray nozzles exposed to condensation. Further evaluation is documented in Section 3.2.2.2.3.
3.2.1-007	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191 for component types listed but is also used for stainless steel heat exchanger components and stainless steel and CASS components in the Reactor Vessels, Internals, and Reactor Coolant System and for stainless steel HVAC closure bolting in the Auxiliary Systems. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of stainless steel and CASS piping, piping components, HVAC closure bolting, and heat exchanger components exposed to air indoor uncontrolled, air outdoor, or condensation Further evaluation is documented in Section 3.2.2.2.4.
3.2.1-008	Not applicable. This line item only applies to PWRs.				
3.2.1-009	Not applicable. This line item only applies to PWRs.				

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-010	Cast austenitic stainless steel piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless steel (CASS)"	No	Not applicable. There are no CASS components exposed to treated borated water or treated water with temperatures greater than 250°C (482°F) in the ESF systems.
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. The Flow-Accelerated Corrosion (B.2.3.9) AMP is used to manage wall thinning of steel piping and piping components exposed to treated water.
3.2.1-012	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, "Bolting Integrity"	No	Not applicable. There is no high-strength steel closure bolting in the ESF systems.
3.2.1-014	Stainless steel, steel, nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of material of stainless steel and steel closure bolting exposed to an air indoor uncontrolled environment. This line is also used for nickel alloy closure bolting in the Reactor Vessels, Internals, and Reactor Coolant System.
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. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of preload of metallic closure bolting in air indoor uncontrolled and treated water environments.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line item is also applied to heat exchangers and components in the components in the Reactor Vessels, Internals, and Reactor Coolant System. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping, piping components, and heat exchangers exposed to treated water and reactor coolant.
3.2.1-017	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum piping or piping components in the ESF systems.
3.2.1-019	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer of stainless steel heat exchanger tubes exposed to treated water.
3.2.1-020	Not applicable. This line item only applies to PWRs.				

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-022	Nickel alloy, stainless steel heat exchanger components, piping, piping components, tanks exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel heat exchanger components, piping, and piping components exposed to treated water.
3.2.1-023	Steel heat exchanger components, piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no steel components in the ESF systems exposed to raw water.
3.2.1-024	Not applicable. This line item only applies to PWRs.				
3.2.1-025	Stainless steel heat exchanger components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not used. Loss of material and flow blockage in stainless steel heat exchanger components exposed to raw water in the ESF systems is addressed in item 3.3.1-040.
3.2.1-027	Stainless steel, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not used. Reduction of heat transfer in stainless steel heat exchanger tubes exposed to raw water is addressed in item 3.3.1-042.
3.2.1-028	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel piping or piping components in the ESF systems exposed to closed-cycle cooling water greater than 60°C (>140°F).

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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 or piping components in the ESF systems exposed to closed-cycle cooling water.
3.2.1-030	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage loss of material of steel heat exchanger components exposed to closed-cycle cooling water.
3.2.1-031	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage loss of material of stainless steel RHR, and recirculation pump seal cooler heat exchanger tubes exposed to closed-cycle cooling water.
3.2.1-032	Copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper alloy heat exchanger components in the ESF systems exposed to closed-cycle cooling water.
3.2.1-033	Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper alloy or stainless steel heat exchanger tubes with a heat transfer function in the ESF systems exposed to closed-cycle cooling water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-034	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. The Selective Leaching (B.2.3.21) AMP is used to manage loss of material in copper alloy >15% Zn heat exchanger tubes exposed to treated water.
3.2.1-035	Not applicable. This line item only applies to PWRs.				
3.2.1-036	Not applicable. This line item only applies to PWRs.				
3.2.1-037	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no gray cast iron or ductile iron piping, or piping components exposed to soil in the ESF systems.
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage hardening or loss of strength due to elastomer degradation in elastomer components exposed to air indoor uncontrolled.
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.2.3.23) AMP is used to manage loss of material of steel external surfaces exposed to air indoor uncontrolled.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-042	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no aluminum piping, piping components in the ESF systems. Further evaluation is documented in Section 3.2.2.2.10.
3.2.1-043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage hardening or loss of strength in elastomer ducting and components exposed air indoor uncontrolled.
3.2.1-044	Steel piping, piping components, ducting, ducting components exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. This line item is also applied to heat exchangers. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of steel piping, piping components, heat exchangers, ducting and components exposed to indoor air uncontrolled.
3.2.1-045	Not applicable. This line item only applies to PWRs.				

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
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. This line item is also applied to heat exchangers. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of steel piping, piping components, and heat exchangers exposed to condensation.
3.2.1-047	Not applicable. This line item only applies to PWRs.				
3.2.1-048	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel and nickel alloy piping and piping components exposed to condensation. Further evaluation is documented in Section 3.2.2.2.2.
3.2.1-049	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping and piping components exposed to lubricating oil.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-050	Copper alloy, stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. This line item is also applied to heat exchangers. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy and stainless steel piping, piping components, and heat exchanger components exposed to lubricating oil.
3.2.1-051	Steel, copper alloy, stainless steel heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage the reduction of heat transfer in copper alloy and stainless steel heat exchanger tubes exposed to lubricating oil.
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	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to managed loss of material of steel piping and piping components exposed to soil.
3.2.1-053	Stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. The ESF systems does not include any stainless steel or nickel alloy piping components exposed to soil or concrete.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-054	Stainless steel, nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Not used. The ESF systems does not include any Class 1 stainless steel or nickel alloy piping components. Cracking of stainless steel piping and piping components exposed to high temperature treated water is addressed by item 3.2.1-114.
3.2.1-055	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not applicable. There are no steel piping or piping components exposed to concrete in the ESF systems. Further evaluation is documented in Section 3.2.2.2.9.
3.2.1-056	Aluminum piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP-XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. There are no aluminum piping, piping components in the ESF systems. Further evaluation is documented in Section 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 Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for copper alloy <15% Zn piping and piping components exposed to air-indoor uncontrolled or condensation. Cracking in copper alloy with >15% Zn piping and piping components exposed to air-indoor uncontrolled and outdoor air is addressed in item 3.4.1-106. Ammonia-based compounds cannot accumulate inside of piping and piping components, so cracking is not an applicable aging effect for internal surfaces.
3.2.1-058	Not applicable. This line item only applies to PWRs.				
3.2.1-059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Not applicable. There are no galvanized steel components exposed to air – indoor controlled in the ESF systems.
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. There are no aging effects that require management for glass piping elements exposed to lubricating oil, treated water, or air indoor uncontrolled.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no nickel alloy piping or piping components exposed to air with borated water leakage in the ESF systems.
3.2.1-063	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for stainless steel piping and piping components exposed to gas.
3.2.1-064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for steel piping and piping components exposed to gas.
3.2.1-065	Metallic piping, piping components exposed to treated water, treated borated water	Wall thinning due to erosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion (B.2.3.9) AMP is used to manage wall thinning of metallic piping and piping components exposed to treated water.
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. Based on a review of MNGP OE, there are no instances of recurring internal corrosion in the ESF systems. Further evaluation is documented in Section 3.2.2.2.7.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-067	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems.
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 tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems.
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 used. Insulated steel piping in the ESF systems is addressed by line item 3.2.1-040.
3.2.1-070	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water, treated borated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-071	Insulated copper alloy (>15% Zn or >8% Al) piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no insulated copper alloy piping components in the ESF systems.
3.2.1-072	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not used. The loss of coating or lining integrity in internally coated carbon steel heat exchanger components exposed to raw water is addressed in item 3.3.1-138.
3.2.1-073	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not used. The loss of material in internally coated carbon steel heat exchanger components exposed to raw water is addressed in item 3.3.1-139.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-074	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. There are no gray cast iron or ductile iron piping, piping components with internal coatings in the ESF systems.
3.2.1-076	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to treated water, treated borated water, raw water, waste water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC (steel, copper alloy in raw water, waste water only)	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of material of stainless steel bolting exposed to treated water.
3.2.1-078	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage cracking in carbon steel piping, piping components exposed to soil.
3.2.1-079	Stainless steel closure bolting exposed to air, soil, concrete, underground	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage cracking of stainless steel closure bolting exposed to air indoor uncontrolled.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect / Mechanism	Aging Management Program / TLAA	Further Evaluation Recommended	Discussion
3.2.1-080	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Not applicable. The ESF systems do not include any stainless steel underground piping, piping components, or tanks. Further evaluation is documented in Section 3.2.2.2.4.
3.2.1-081	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. This line item is used for components in the Auxiliary Systems. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage reduction of heat transfer due to fouling of stainless steel and copper alloy heat exchanger components exposed to air.
3.2.1-087	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic insulation. This item is also used in the Hangers and Supports Commodity Group system.
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. The One-Time Inspection (B.2.3.20) AMP is used to manage long-term loss of material of steel components exposed to treated water.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-091	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not applicable. There are no stainless steel piping and piping components exposed to concrete in the ESF systems. Further evaluation is documented in Section 3.2.2.2.9.
3.2.1-096	Steel, stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel or stainless steel piping or piping components exposed to raw water not covered by NRC GL 89-13 in the ESF systems.
3.2.1-098	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no copper alloy piping or piping components exposed to soil in the ESF systems.
3.2.1-099	Stainless steel, nickel alloy tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Not applicable. There are no stainless steel tanks in the ESF systems. Further evaluation is documented in Section 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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-100	Aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water, waste water	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no aluminum piping or piping components in the ESF systems. Further evaluation is documented in Section 3.2.2.2.8.
3.2.1-101	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no aluminum piping, piping components, or tanks in the ESF systems. Further evaluation is documented in Section 3.2.2.2.8.
3.2.1-102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks AMP in the ESF systems. Further evaluation is documented in Section 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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-103	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems. Further evaluation is documented in Section 3.2.2.2.4.
3.2.1-104	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems.
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 tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems. Further evaluation is documented in Section 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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-106	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems. Further evaluation is documented in Section 3.2.2.2.2.
3.2.1-107	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of insulated stainless steel piping and piping components exposed to air. Further evaluation is documented in Section 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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2.1-108	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of insulated stainless steel piping and piping components exposed to air. Further evaluation is documented in Section 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, or tanks in the ESF systems. Further evaluation is documented in Section 3.2.2.2.8.
3.2.1-110	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. There are no underground aluminum piping, piping components, or tanks in the ESF systems. Further evaluation is documented in Section 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 Program / TLAA	Further Evaluation Recommended	Discussion
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 underground aluminum piping, piping components, or tanks in the ESF systems. Further evaluation is documented in Section 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 or nickel alloy underground piping, piping components, or tanks in the ESF systems. Further evaluation is documented in Section 3.2.2.2.2.
3.2.1-114	Stainless steel, nickel alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel components exposed to treated water >60°C (>140°F).
3.2.1-115	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no titanium heat exchanger tubes in the ESF systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 heat exchanger components, piping, or piping components in the ESF systems.
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 in the ESF systems.
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 heat exchanger components, piping, or piping components in the ESF systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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, or tanks in the ESF systems. Further evaluation is documented in Section 3.2.2.2.10.
3.2.1-120	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no aluminum piping, piping components, or tanks exposed to soil in the ESF systems.
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, or tanks exposed to raw water or waste water in the ESF systems. Further evaluation is documented in Section 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 Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of elastomer ducting and components exposed to air.
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of elastomer ducting and components exposed to air.
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, or tanks in the ESF systems.
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 bolts exposed to soil, concrete, or underground in the ESF systems.
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. The are no titanium or super austenitic piping, piping components, tanks, or closure bolting in the ESF systems.
3.2.1-127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. The are no copper alloy piping or piping components exposed to concrete in the ESF systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**Further Evaluation Recommended**	**Discussion**
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 or piping components exposed to soil or underground in the ESF systems.
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 tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the ESF systems.
3.2.1-130	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel heat exchanger components exposed to lubricating oil.
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 or piping components exposed to raw water in the ESF systems.
3.2.1-132	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no titanium components in the ESF systems.
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 components in the ESF systems.

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program / TLAA**	**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 components in the ESF systems.

Table 3.2.2-1: Core Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	V.E.E-421	3.2.1-079	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tubes	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.G.SP-79	3.4.1-044	A

Table 3.2.2-1: Core Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tubes	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.G.SP-79	3.4.1-044	A
Heat Exchanger - (Core Spray Pump Motor Oil Cooler) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	V.D2.EP-91	3.3.1-040	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.3.1-007	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.3.1-007	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-1: Core Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.3.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Pump Casing (Core Spray)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (Core Spray)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Pump Casing (Core Spray)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Pump Casing (Core Spray)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B

Table 3.2.2-1: Core Spray – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.3.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Blower Housing (HPCI Turbine Gland Seal Condenser)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Blower Housing (HPCI Turbine Gland Seal Condenser)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	V.E.E-421	3.2.1-079	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.3.1-015	A
Heat Exchanger - (HPCI Gland Seal Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (HPCI Gland Seal Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (HPCI Gland Seal Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (HPCI Gland Seal Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3.1-022	C
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	V.D2.EP-37	3.2.1-034	A
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-140	3.3.1-022	D

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3.1-022	C
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	V.D2.EP-37	3.2.1-034	A
Heat Exchanger - (HPCI Gland Seal Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-140	3.3.1-022	D
Heat Exchanger - (HPCI Lubricating Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-78	3.2.1-051	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	V.D2.EP-78	3.2.1-051	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	VIII.E.SP-100	3.4.1-018	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.3.2)	VIII.E.SP-100	3.4.1-018	B
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-76	3.2.1-050	C
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2.1-050	C

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3.1-022	C
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	V.D2.EP-37	3.2.1-034	A
Heat Exchanger - (HPCI Lubricating Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-140	3.3.1-022	D
Insulation - Thermal	Thermal Insulation	Fiberglass	Air - Indoor Uncontrolled (External)	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-422	3.2.1-087	A
Orifice	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Orifice	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Orifice	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Orifice	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-61b	3.2.1-048	A

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.C1.AP-138	3.3.1-100	A
Orifice	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-138	3.3.1-100	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Orifice	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2.1-114	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	V.D2.E-457	3.2.1-114	B
Orifice	Throttle	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Orifice	Throttle	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Orifice	Throttle	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Throttle	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-61b	3.2.1-048	A
Orifice	Throttle	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.C1.AP-138	3.3.1-100	A
Orifice	Throttle	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-138	3.3.1-100	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Orifice	Throttle	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2.1-114	A

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Throttle	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	V.D2.E-457	3.2.1-114	B
Piping Elements	Pressure Boundary	Glass	Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-060	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2.1-011	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2.1-011	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-76	3.2.1-050	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2.1-050	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.C1.AP-138	3.3.1-100	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-138	3.3.1-100	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2.1-114	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	V.D2.E-457	3.2.1-114	B
Pump Casing (HPCI Booster)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (HPCI Booster)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Pump Casing (HPCI Booster)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Pump Casing (HPCI Booster)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Pump Casing (HPCI Turbine Aux Oil)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (HPCI Turbine Aux Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Pump Casing (HPCI Turbine Aux Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Pump Casing (HPCI Turbine Driven Lubricating Oil)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (HPCI Turbine Driven Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Pump Casing (HPCI Turbine Driven Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Pump Casing (HPCI Turbine Gland Seal CDSR Drain)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (HPCI Turbine Gland Seal CDSR Drain)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Pump Casing (HPCI Turbine Gland Seal CDSR Drain)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Pump Casing (HPCI Turbine Gland Seal CDSR Drain)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Pump Casing (HPCI)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (HPCI)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Pump Casing (HPCI)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Pump Casing (HPCI)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Strainer (Element)	Filter	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Strainer (Element)	Filter	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Tanks (CV-2065 Accumulator)	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Tanks (CV-2065 Accumulator)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Tanks (HPCI Turbine Lubricating Oil)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Tanks (HPCI Turbine Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	C
Tanks (HPCI Turbine Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	C

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Turbine Casings (HPCI Drive)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Turbine Casings (HPCI Drive)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-76	3.2.1-050	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2.1-050	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-61b	3.2.1-048	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Valve Body	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2.1-114	A

Table 3.2.2-2: High Pressure Coolant Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	V.D2.E-457	3.2.1-114	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (Instrument Air)	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Accumulator (Instrument Air)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Accumulator (Instrument Air)	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	V.E.E-421	3.2.1-079	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Heat Exchanger - (Primary Containment Purge Vaporizer) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (Primary Containment Purge Vaporizer) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Primary Containment Purge Vaporizer) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	C
Heat Exchanger - (Primary Containment Purge Vaporizer) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (Primary Containment Purge Vaporizer) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	C
Heat Exchanger - (Primary Containment Purge Vaporizer) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	C
Heat Exchanger - (Primary Containment Purge Vaporizer) Tube Side Components	Leakage Boundary	Stainless Steel	Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	C
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Rupture Disks	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Rupture Disks	Pressure Boundary	Nickel Alloy	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-61b	3.2.1-048	A
Strainer (Element)	Filter	Carbon Steel	Condensation (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-404	3.3.1-131	E, 1
Strainer (Element)	Filter	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	None	None	V.F.EP-10	3.2.1-057	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	V.F.EP-22	3.2.1-063	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Structural Integrity (Attached)	Carbon Steel	Gas (Internal)	None	None	V.F.EP-7	3.2.1-064	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A

Table 3.2.2-3: Primary Containment Mechanical – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is being substituted for the Fire Water System (B.2.3.16) program to manage flow blockage of the carbon steel strainer element components exposed to condensation.

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator (CV-2104 Minimum Flow Valve Accumulator)	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Accumulator (CV-2104 Minimum Flow Valve Accumulator)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	V.E.E-421	3.2.1-079	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Heat Exchanger - (RCIC Barometric Condenser and Vacuum Tank) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	C
Heat Exchanger - (RCIC Barometric Condenser and Vacuum Tank) Shell Side Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	C

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (RCIC Barometric Condenser and Vacuum Tank) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Heat Exchanger - (RCIC Barometric Condenser and Vacuum Tank) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-60	3.2.1-016	C
Heat Exchanger - (RCIC Barometric Condenser and Vacuum Tank) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.E-60	3.2.1-016	D
Heat Exchanger - (RCIC Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (RCIC Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (RCIC Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (RCIC Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (RCIC Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (RCIC Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Heat Exchanger - (RCIC Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	C
Heat Exchanger - (RCIC Oil Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RCIC Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (RCIC Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Heat Exchanger - (RCIC Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	C
Heat Exchanger - (RCIC Oil Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RCIC Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-78	3.2.1-051	A
Heat Exchanger - (RCIC Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	V.D2.EP-78	3.2.1-051	A
Heat Exchanger - (RCIC Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	VIII.E.SP-100	3.4.1-018	A
Heat Exchanger - (RCIC Oil Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Reduction of Heat Transfer	Water Chemistry (B.2.3.2)	VIII.E.SP-100	3.4.1-018	B
Heat Exchanger - (RCIC Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-76	3.2.1-050	C

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (RCIC Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-76	3.2.1-050	C
Heat Exchanger - (RCIC Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-140	3.3.1-022	C
Heat Exchanger - (RCIC Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	V.D2.EP-37	3.2.1-034	A
Heat Exchanger - (RCIC Oil Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-140	3.3.1-022	D
Orifice	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Orifice	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Orifice	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Orifice	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-61b	3.2.1-048	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Orifice	Throttle	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Orifice	Throttle	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Orifice	Throttle	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Orifice	Throttle	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Throttle	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-61b	3.2.1-048	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping Elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2.1-060	A
Piping Elements	Leakage Boundary	Glass	Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2.1-060	A
Piping Elements	Leakage Boundary	Glass	Treated Water (Internal)	None	None	V.F.EP-29	3.2.1-060	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2.1-011	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2.1-011	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-408	3.2.1-065	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.E-457	3.2.1-114	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	V.D2.E-457	3.2.1-114	B
Pump Casing (Lubricating Oil)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-131	3.3.1-098	C
Pump Casing (Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3.1-098	C
Pump Casing (RCIC Barometric Condenser Vacuum Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (RCIC Barometric Condenser Vacuum Pump)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Pump Casing (RCIC Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (RCIC Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Pump Casing (RCIC Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Pump Casing (RCIC Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Pump Casing (RCIC Turbine Barometric Condenser Condensate Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (RCIC Turbine Barometric Condenser Condensate Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Pump Casing (RCIC Turbine Barometric Condenser Condensate Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Pump Casing (RCIC Turbine Barometric Condenser Condensate Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Strainer (Element)	Filter	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Strainer (Element)	Filter	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Strainer (Element)	Filter	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Strainer (Element)	Filter	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Strainer (Element)	Filter	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Turbine Casings (RCIC Terry Turbine)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Turbine Casings (RCIC Terry Turbine)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-27	3.2.1-046	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-77	3.2.1-049	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-77	3.2.1-049	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A

Table 3.2.2-4: Reactor Core Isolation Cooling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-61b	3.2.1-048	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator (Minimum Flow Valve Accumulators)	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Accumulator (Minimum Flow Valve Accumulators)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	V.E.E-421	3.2.1-079	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-418	3.2.1-076	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Treated Water (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Heat Exchanger - (RHR Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (RHR Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Heat Exchanger - (RHR Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	C

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (RHR Heat Exchanger) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	C
Heat Exchanger - (RHR Heat Exchanger) Tube Sheet	Pressure Boundary	Carbon or Low Alloy Steel with Stainless Steel Cladding	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	D
Heat Exchanger - (RHR Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (RHR Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3.1-038	A

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (RHR Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3.1-138	A
Heat Exchanger - (RHR Heat Exchanger) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-414	3.3.1-139	E, 2
Heat Exchanger - (RHR Heat Exchanger) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3.1-042	A
Heat Exchanger - (RHR Heat Exchanger) Tubes	Heat Transfer	Stainless Steel	Treated Water (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	V.D2.EP-74	3.2.1-019	A
Heat Exchanger - (RHR Heat Exchanger) Tubes	Heat Transfer	Stainless Steel	Treated Water (External)	Reduction of Heat Transfer	Water Chemistry (B.2.3.2)	V.D2.EP-74	3.2.1-019	B
Heat Exchanger - (RHR Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	C
Heat Exchanger - (RHR Heat Exchanger) Tubes	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	D
Heat Exchanger - (RHR Pump Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (RHR Pump Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (RHR Pump Oil Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-473	3.2.1-130	A
Heat Exchanger - (RHR Pump Oil Cooler) Tubes	Heat Transfer	Stainless Steel	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-79	3.2.1-051	A

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (RHR Pump Oil Cooler) Tubes	Heat Transfer	Stainless Steel	Lubricating Oil (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	V.D2.EP-79	3.2.1-051	A
Heat Exchanger - (RHR Pump Oil Cooler) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3.1-042	A
Heat Exchanger - (RHR Pump Oil Cooler) Tubes	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.G.SP-79	3.4.1-044	A
Heat Exchanger - (RHR Pump Oil Cooler) Tubes	Pressure Boundary	Stainless Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.G.SP-79	3.4.1-044	A
Heat Exchanger - (RHR Pump Oil Cooler) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (RHR Pump Oil Cooler) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Heat Exchanger - (RHR Pump Seal Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (RHR Pump Seal Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Heat Exchanger - (RHR Pump Seal Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	C
Heat Exchanger - (RHR Pump Seal Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RHR Pump Seal Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-92	3.2.1-030	A
Heat Exchanger - (RHR Pump Seal Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Heat Exchanger - (RHR Pump Seal Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	C

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (RHR Pump Seal Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	D
Heat Exchanger - (RHR Pump Seal Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Heat Exchanger - (RHR Pump Seal Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-92	3.2.1-030	A
Heat Exchanger - (RHR Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	V.D2.EP-93	3.2.1-031	A
Heat Exchanger - (RHR Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	C
Heat Exchanger - (RHR Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	D
Insulation - Thermal	Thermal Insulation	Fiberglass	Air - Indoor Uncontrolled (External)	Reduced Thermal Insulation Resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-422	3.2.1-087	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	V.D2.E-09	3.2.1-011	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Pump Casing (RHR Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Pump Casing (RHR Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Pump Casing (RHR Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Pump Casing (RHR Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Flow Blockage	One-Time Inspection (B.2.3.20)	V.D2.EP-113a	3.2.1-006	A
Strainer (Element)	Filter	Stainless Steel	Treated Water (External)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	None	None	H, 1
Strainer (Element)	Filter	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Strainer (Element)	Filter	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B

Table 3.2.2-5: Residual Heat Removal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-73	3.2.1-022	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-73	3.2.1-022	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

H. Aging effect not in NUREG-2191 for this component, material, and environment combination.

Plant-Specific Notes

1. Flow blockage due to fouling in the ECCS suction strainers will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program which includes periodic inspections to ensure strainers are free of excessive debris that could cause flow blockage.

2. The Open-Cycle Cooling Water System (B.2.3.11) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage the loss of material in the base metal of the carbon steel (with internal coating) heat exchanger components exposed to raw water.

Table 3.2.2-6: Secondary Containment – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Blower Housing (Fan)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Blower Housing (Fan)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	V.E.E-02	3.2.1-014	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	V.E.EP-116	3.2.1-015	A
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F2.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F2.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Copper Alloy with 15% Zinc or Less Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F2.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	C
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F2.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F2.A-794	3.3.1-260	A
Ducting and Components	Filter	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A

Table 3.2.2-6: Secondary Containment – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Ducting and Components	Filter	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Ducting and Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-08	3.3.1-090	A
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.EP-59	3.2.1-038	A
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-465	3.2.1-122	A
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-427	3.2.1-043	A
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-466	3.2.1-123	A
Ducting and Components	Pressure Boundary	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	C
Ducting and Components	Pressure Boundary	Galvanized Steel	Air - Indoor Uncontrolled (Internal)	None	None	VII.J.AP-13	3.3.1-116	C

Table 3.2.2-6: Secondary Containment – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Ducting and Components	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	C
Ducting and Components	Pressure Boundary	Glass	Air - Indoor Uncontrolled (Internal)	None	None	VII.J.AP-48	3.3.1-117	C
Ducting and Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.A-781a	3.3.1-094a	A
Ducting and Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.AP-99a	3.3.1-094	A
Ducting and Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.A-781a	3.3.1-094a	A
Ducting and Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.AP-99a	3.3.1-094	A
Orifice	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Orifice	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	C
Orifice	Throttle	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Orifice	Throttle	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	C

Table 3.2.2-6: Secondary Containment – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	C
Piping, Piping Components	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.EP-111	3.2.1-052	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (Internal)	None	None	V.F.EP-10	3.2.1-057	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.AP-221a	3.3.1-006	A

Table 3.2.2-6: Secondary Containment – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	V.E.E-420	3.2.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-44	3.2.1-040	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	C
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.E-434	3.2.1-090	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-60	3.2.1-016	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	V.D2.EP-60	3.2.1-016	B
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-10	3.2.1-057	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (Internal)	None	None	V.F.EP-10	3.2.1-057	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	A

Table 3.2.2-6: Secondary Containment – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.3.20)	V.C.EP-103b	3.2.1-007	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.C.EP-107a	3.2.1-004	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

None.

3.3 AGING MANAGEMENT OF AUXILIARY SYSTEMS

3.3.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.3.3, *Auxiliary Systems*, as being subject to AMR. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Alternate Nitrogen (2.3.3.1)
- Chemistry Sampling (2.3.3.2)
- Circulating Water (2.3.3.3)
- Control Rod Drive (2.3.3.4)
- Demineralized Water (2.3.3.5)
- Emergency Diesel Generators (2.3.3.6)
- Emergency Filtration Train (2.3.3.7)
- Emergency Service Water (2.3.3.8)
- Fire System (2.3.3.9)
- Fuel Pool Cooling and Cleanup (2.3.3.10)
- Heating and Ventilation (2.3.3.11)
- Instrument and Service Air (2.3.3.12)
- Radwaste Solid and Liquid (2.3.3.13)
- Reactor Building Closed Cooling Water (2.3.3.14)
- Reactor Water Cleanup (2.3.3.15)
- Service and Seal Water (2.3.3.16)
- Standby Liquid Control (2.3.3.17)
- Wells and Domestic Water (2.3.3.18)

3.3.2 Results

Table 3.3.2-1, Alternate Nitrogen – Summary of Aging Management Evaluation

Table 3.3.2-2, Chemistry Sampling – Summary of Aging Management Evaluation

Table 3.3.2-3, Circulating Water – Summary of Aging Management Evaluation

Table 3.3.2-4, Control Rod Drive – Summary of Aging Management Evaluation

Table 3.3.2-5, Demineralized Water – Summary of Aging Management Evaluation

Table 3.3.2-6, Emergency Diesel Generators – Summary of Aging Management Evaluation

Table 3.3.2-7, Emergency Filtration Train – Summary of Aging Management Evaluation

Table 3.3.2-8, Emergency Service Water – Summary of Aging Management Evaluation

Table 3.3.2-9, Fire System – Summary of Aging Management Evaluation

Table 3.3.2-10, Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation

Table 3.3.2-11, Heating and Ventilation – Summary of Aging Management Evaluation

Table 3.3.2-12, Instrument and Service Air – Summary of Aging Management Evaluation

Table 3.3.2-13, Radwaste Solid and Liquid – Summary of Aging Management Evaluation

Table 3.3.2-14, Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation

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

Table 3.3.2-16, Service and Seal Water – Summary of Aging Management Evaluation

Table 3.3.2-17, Standby Liquid Control – Summary of Aging Management Evaluation

Table 3.3.2-18, Wells and Domestic Water – Summary of Aging Management Evaluation

3.3.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Alternate Nitrogen

Materials

The materials of construction for the AN2 System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with Greater Than 15% Zinc
- Stainless Steel
- Stainless Steel Bolting

Environment

The AN2 System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Gas

Aging Effects Requiring Management

The following aging effects associated with the AN2 System require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the AN2 System components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- One-Time Inspection (B.2.3.20)

3.3.2.1.2 Chemistry Sampling

Materials

The materials of construction for the CHM System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Stainless Steel
- Stainless Steel Bolting

Environments

The CHM System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the CHM System require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the CHM System components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.3 Circulating Water

Materials

The materials of construction for the CWT System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon steel with Internal Coating
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environment

The CWT System components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Condensation
- Raw Water
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the CWT System require management:

- Cracking
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the CWT System components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)

3.3.2.1.4 Control Rod Drive

Materials

The materials of construction for the CRD System components are:

- Aluminum
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less
- Stainless Steel
- Stainless Steel Bolting

Environment

The CRD System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Dry
- Closed-Cycle Cooling Water
- Condensation
- Gas
- Lubricating Oil
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the CRD System require management:

- Cracking
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following AMPs manage the aging effects for the CRD System components:

- Bolting Integrity (B.2.3.10)
- Closed Treated Water Systems (B.2.3.12)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.5 Demineralized Water

Materials

The materials of construction for the DWS components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Carbon Steel with Internal Coating
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Fiberglass
- Galvanized Steel
- Polymer
- PVC
- Stainless Steel
- Stainless Steel Bolting

Environment

The DWS components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Condensation
- Raw Water
- Treated Water
- Treated Water >140 F

Aging Effects Requiring Management

The following aging effects associated with the DWS require management:

- Cracking
- Cracking, Blistering, Loss of Material
- Hardening or Loss of Strength
- Long-Term Loss of Material

- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the DWS components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.6 Emergency Diesel Generators

Materials

The materials of construction for the DGN System components are:

- Aluminum
- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Glass
- Gray Cast Iron
- Gray Cast Iron with Internal Coating
- Stainless Steel
- Stainless Steel Bolting

Environment

The DGN System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Closed-Cycle Cooling Water
- Condensation
- Diesel Exhaust
- Fuel Oil
- Lubricating Oil
- Raw Water

- Soil
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the DGN System require management:

- Cracking
- Flow Blockage
- Hardening and Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the DGN System components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Fuel Oil Chemistry (B.2.3.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Selective Leaching (B.2.3.21)

3.3.2.1.7 Emergency Filtration Train

Materials

The materials of construction for the EFT System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Copper Alloy with Greater Than 15% Zinc
- Elastomer
- Stainless Steel
- Stainless Steel Bolting

Environments

The EFT System components are exposed to the following environments:

- Air - Indoor Controlled
- Air - Indoor Uncontrolled
- Air - Outdoor
- Gas
- Raw Water

Aging Effects Requiring Management

The following aging effects associated with the EFT System require management:

- Cracking
- Flow Blockage
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

Aging Management Programs

The following AMPs manage the aging effects for the EFT System components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Selective Leaching (B.2.3.21)

3.3.2.1.8 Emergency Service Water

Materials

The materials of construction for the ESW System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Carbon Steel with Internal Coating
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Gray Cast Iron

- Stainless Steel
- Stainless Steel Bolting

Environments

The ESW System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Condensation
- Lubricating Oil
- Raw Water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the ESW System require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the ESW System components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Selective Leaching (B.2.3.21)

3.3.2.1.9 Fire System

Materials

The materials of construction for the FIR System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with Greater Than 15% Zinc
- Copper Alloy with 15% Zinc or Less
- Ductile Iron
- Elastomer
- Galvanized Steel
- Glass
- Gray Cast Iron
- Gray Cast Iron with Internal Coating
- Polymer
- PVC
- Stainless Steel
- Stainless Steel Bolting

Environments

The FIR System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Closed-Cycle Cooling Water
- Condensation
- Diesel Exhaust
- Gas
- Raw Water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the FIR System require management:

- Cracking
- Flow Blockage
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the FIR System components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Fire Protection (B.2.3.15)
- Fire Water System (B.2.3.16)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)

3.3.2.1.10 Fuel Pool Cooling and Cleanup

Materials

The materials of construction for the FPC System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Copper Alloy with Greater Than 15% Zinc
- Copper Alloy with 15% Zinc or Less
- Stainless Steel
- Stainless Steel Bolting

Environments

The FPC System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed-Cycle Cooling Water
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the FPC System require management:

- Cracking
- Loss of Coating or Lining Integrity
- Loss of Material
- Long-Term Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the FPC System components:

- Bolting Integrity (B.2.3.10)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.11 Heating and Ventilation

Materials

The materials of construction for the HTV System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The HTV System components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Closed-Cycle Cooling Water
- Condensation
- Gas
- Raw Water
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the HTV System 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 AMPs manage the aging effects for the HTV System components:

- Bolting Integrity (B.2.3.10)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.12 Instrument and Service Air

Materials

The materials of construction for the AIR System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less
- Stainless Steel
- Stainless Steel Bolting

Environments

The AIR System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Gas

Aging Effects Requiring Management

The following aging effects associated with the AIR System require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the AIR System components:

- Bolting Integrity (B.2.3.10)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- One-Time Inspection (B.2.3.20)

3.3.2.1.13 Radwaste Solid and Liquid

Materials

The materials of construction for the RAD System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with Greater Than 15% Zinc
- Gray Cast Iron
- Gray Cast Iron with Internal Coating
- Stainless Steel
- Stainless Steel Bolting

Environments

The RAD System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Closed-Cycle Cooling Water
- Concrete
- Condensation
- Treated Water
- Waste Water
- Waste Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the RAD System require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the RAD System components:

- Bolting Integrity (B.2.3.10)
- Closed Treated Water Systems (B.2.3.12)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)

- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.3.2.1.14 Reactor Building Closed Cooling Water

Materials

The materials of construction for the RBC System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The RBC System components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Closed-Cycle Cooling Water
- Condensation
- Raw Water

Aging Effects Requiring Management

The following aging effects associated with the RBC System require management:

- Cracking
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the RBC System components:

- Bolting Integrity (B.2.3.10)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)

- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)

3.3.2.1.15 Reactor Water Cleanup

Materials

The materials of construction for the RWC System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with Greater than 15% Zinc
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The RWC System components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Closed-Cycle Cooling Water
- Closed-Cycle Cooling Water >140°F
- Lubricating Oil
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the RWC System require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the RWC System components:

- Bolting Integrity (B.2.3.10)
- Closed Treated Water Systems (B.2.3.12)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.16 Service and Seal Water

Materials

The materials of construction for the SSW System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Copper Alloy with 15% Zinc or Less
- Elastomer
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The SSW System components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Condensation
- Lubricating Oil
- Raw Water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the SSW System require management:

- Cracking
- Flow Blockage
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the SSW System components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)

- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)
- Open-Cycle Cooling Water System (B.2.3.11)
- Selective Leaching (B.2.3.21)

3.3.2.1.17 Standby Liquid Control

Materials

The materials of construction for the SLC System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Cast Austenitic Stainless Steel
- Elastomer
- Stainless Steel
- Stainless Steel Bolting

Environments

The SLC System components are exposed to the following environments:

- Air – Dry
- Air – Indoor Uncontrolled
- Concrete
- Condensation
- Gas
- Sodium Pentaborate Solution
- Treated Water
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the SLC System require management:

- Cracking
- Flow Blockage
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the SLC System components:

- Bolting Integrity (B.2.3.10)
- Compressed Air Monitoring (B.2.3.14)

- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.3.2.1.18 Wells and Domestic Water

Materials

The materials of construction for the WDW System components are:

- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with Greater Than 15% Zinc
- Gray Cast Iron
- Stainless Steel Bolting

Environments

The WDW components are exposed to the following environments:

- Air – Indoor Uncontrolled
- Concrete
- Raw Water
- Waste Water

Aging Effects Requiring Management

The following aging effects associated with the WDW System require management:

- Cracking
- Flow Blockage
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the WDW components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)

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 SLRA. For the Auxiliary Systems, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

Line items 3.3.1-265 through 3.3.1-269 were added to Table 3.3-1 based on changes associated with SLR-ISG-2021-02-MECHANICAL.

3.3.2.2.1 Cumulative Fatigue Damage

> *Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.*

Cumulative fatigue damage of Auxiliary Systems components, as described in SRP-SLR Item 3.3.2.2.1, is addressed as a TLAA in Section 4.3, *Metal Fatigue*.

Cumulative fatigue of cranes and lifting devices is evaluated and dispositioned as a TLAA for the Cranes, Heavy Loads, Rigging System as discussed in Section 4.6.1.

Identification of components subject to this aging effect are addressed in Sections 4.3 and 4.6.1 only and not in AMR Tables 3.3.2-X because all Auxiliary Systems components have been dispositioned as 10 CFR 54.21(c)(1)(i) and do not require aging management.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

> *Cracking due to stress corrosion cracking (SCC) and cyclic loading could occur in stainless steel (SS) PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (Celsius) [140 °F (Fahrenheit)] in the chemical and volume control system. The existing AMP for monitoring and control of primary water chemistry in PWRs (GALL-SLR Report AMP XI.M2, "Water Chemistry") manages the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that cracking is not occurring. If a search of plant-specific operating experience (OE) does not reveal that cracking has occurred in nonregenerative heat exchanger tubing, this aging effect can be considered to be adequately managed by GALL-SLR Report AMP XI.M2. However, if cracking has occurred in nonregenerative heat exchanger tubing, the GALL-SLR Report recommends that AMP XI.M21A, "Closed Treated Water Systems," be evaluated for inclusion of augmented requirements to conduct*

temperature and radioactivity monitoring of the shell side water, and where component configuration permits, periodic eddy current testing of tubes.

Not applicable. This further evaluation item is applicable to PWRs only.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to SCC could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated, (b) insulated, (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the license renewal application (LRA).

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of *operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.*

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Ambient air at MNGP is not subject to a marine atmosphere. MNGP is located in the vicinity of a major road that is routinely salted for snow and ice. A review of the over 69,000 ARs created during the 01/01/2010 to 07/29/2021 period was performed to determine if the proximity to the salted road has resulted in any plant-specific OE for cracking of the susceptible materials to chlorides in an air environment. The results of this review show that the ambient air environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. As such, stainless steel components exposed to air or condensation in the auxiliary systems are not susceptible to cracking due to SCC.

Plant-specific OE associated with insulated stainless steel components in the auxiliary systems has been evaluated to determine if prolonged exposure to a condensation environment has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at MNGP for insulated stainless steel components for 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.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that cracking is not occurring in stainless steel components exposed to air indoor uncontrolled, air outdoor, and condensation, and, insulated stainless steel components exposed to condensation. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.3.2.2.4 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of *fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Ambient air at MNGP is not subject to a marine atmosphere. MNGP is located in the vicinity of a major road that is routinely salted for snow and ice. A review of the over 69,000 ARs created during the 01/01/2010 to 07/29/2021 period was performed to determine if the proximity to the salted road has resulted in any plant-specific OE for loss of material of the susceptible materials to chlorides in an air environment. The results of this review show that the ambient air environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. As such, stainless steel components exposed to air or condensation in the auxiliary systems are not susceptible to loss of material.

Plant-specific OE associated with insulated stainless steel components in the auxiliary systems has been evaluated to determine if prolonged exposure to a condensation environment has resulted in loss of material due to SCC. Loss of material has not been identified as an aging effect at MNGP for insulated stainless steel components for 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.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that loss of material is not occurring in stainless steel components exposed to air indoor uncontrolled, air outdoor, and condensation, and insulated stainless steel components exposed to condensation. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2 of this SRP-SLR.)

QA provisions applicable to SLR are discussed in Section B.1.3.

3.3.2.2.6 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The OE process and acceptance criteria are described in 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 (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).*

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M20, "Open-Cycle Cooling Water System," GALL-SLR Report AMP XI.M27, "Fire Water System," or GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

Based on plant-specific OE, recurring internal corrosion is an applicable effect for steel components in raw water systems that use water from the Mississippi River. The Open-Cycle Cooling Water System (B.2.3.11) AMP, Fire Water System (B.2.3.16) AMP, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP are enhanced and used to manage loss of material due to the recurring internal corrosion aging effect for steel piping, piping components, tanks, and heat exchanger components exposed to raw water.

3.3.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

Susceptible Material: If the material is not susceptible to SCC then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to

SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. 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.

The results of the OE review show that the ambient air is considered mild. As such, aluminum exposed to air or condensation in the auxiliary systems are not susceptible to cracking.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that cracking is not occurring in aluminum components. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.3.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components, loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

The stainless steel SLC tank is the only stainless steel component exposed to concrete that is susceptible to cracking. Other steel or stainless steel components exposed to concrete is not subject to wetting, so loss of material and cracking are not applicable aging effects. OE has shown cracking of the stainless steel SLC tank bottoms. However, this issue has been corrected and the One-Time Inspection (B.2.3.20) AMP will be used to confirm that the tank bottoms has not experienced further cracking.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) 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.*

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

The results of the OE review show that the ambient air is considered mild. As such, aluminum exposed to air or condensation in the auxiliary systems are not susceptible to loss of material.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that loss of material is not occurring in aluminum components. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in Section B.2.3.20.

3.3.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Auxiliary System components:

- Section 4.3, *Metal Fatigue*
- Section 4.6.1, *Fatigue of Cranes*

3.3.3 <u>Conclusion</u>

Auxiliary Systems piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for Auxiliary System components are identified in the summaries in Section 3.3.2 above.

A description of these AMPs is provided in Appendix B along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with Auxiliary System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-001	Steel cranes: bridges, structural members, structural components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.7, "Other Plant-Specific TLAAs"	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. The Crane Cycle Limits TLAA is used to manage cumulative fatigue damage of steel cranes and associated components. This line item is used to evaluate structural items in Section 3.5. Identification of components subject to this aging effect are addressed in Section 4.6.1 only and not in AMR Tables 3.3.2-X because all Auxiliary Systems components have been dispositioned as 10 CFR 54.21(c)(1)(i) and do not require aging management. Further evaluation is documented in Section 3.3.2.2.1.
3.3.1-002	Stainless steel, steel heat exchanger components and tubes, piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3, "Metal Fatigue"	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. The Section 4.3 Metal Fatigue TLAA is used to manage cumulative fatigue damage in steel and stainless steel piping, and piping components exposed to any environment. Identification of components subject to this aging effect are addressed in Section 4.3 only and not in AMR Tables 3.3.2-X because all Auxiliary Systems components have been dispositioned as 10 CFR 54.21(c)(1)(i) and do not require aging management. Further evaluation is documented in Section 3.3.2.2.1.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-003	Not applicable. This line item only applies to PWRs.				
3.3.1-003a	Not applicable. This line item only applies to PWRs.				
3.3.1-004	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. This line item is also applied to heat exchanger components. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of stainless steel piping, piping components, and heat exchanger components exposed to air indoor uncontrolled, air outdoor, and condensation. Further evaluation is documented in Section 3.3.2.2.3.
3.3.1-006	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. This line item is also applied to heat exchanger components. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel piping, piping components, and heat exchanger components exposed to air indoor uncontrolled, air outdoor, and condensation. Further evaluation is documented in Section 3.3.2.2.4.
3.3.1-007	Not applicable. This line item only applies to PWRs.				
3.3.1-008	Not applicable. This line item only applies to PWRs.				
3.3.1-009	Not applicable. This line item only applies to PWRs.				

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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 is no high-strength bolting associated with the Auxiliary Systems.
3.3.1-012	Steel, stainless steel, nickel alloy closure bolting exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of material of steel and stainless steel closure bolting exposed to air indoor uncontrolled and air outdoor.
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. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of preload in metallic closure bolting exposed to air indoor uncontrolled, air outdoor, raw water, soil, and waste water.
3.3.1-016	Stainless steel piping, piping components outboard the second containment isolation valves with a diameter ≥4 inches nominal pipe size exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M2, "Water Chemistry," and AMP XI.M25, "BWR Reactor Water Cleanup System"	No	Not applicable. There are no stainless steel piping or piping components outboard the second containment isolation valves with a diameter ≥4 inches nominal pipe size exposed to treated water >93°C (>200°F) in the RWC System.
3.3.1-017	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel heat exchanger tubes exposed to treated water or treated borated water with a heat transfer function in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-018	Stainless steel high- pressure pump casing, piping, piping components, tanks exposed to treated borated water >60°C (>140°F), sodium pentaborate solution >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel components exposed to treated borated water 60°C (>140°F), or sodium pentaborate solution >60°C (>140°F).
3.3.1-019	Stainless steel regenerative heat exchanger components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel regenerative heat exchanger components exposed to treated water >60°C (>140°F).
3.3.1-020	Stainless steel, steel with stainless steel cladding heat exchanger components exposed to treated borated water >60°C (>140°F), treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel heat exchanger components exposed to treated water >60°C (>140°F).

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line is also applied to heat exchanger components. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping, piping components, and heat exchanger components exposed to treated water.
3.3.1-022	Copper alloy piping, piping components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line is also applied to heat exchanger components. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy piping, piping components, and heat exchanger components exposed to treated water.
3.3.1-025	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of aluminum components exposed to treated water. This line item is used to evaluate structural items associated with the Cranes, Heavy Loads, Rigging System in Section 3.5.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-026	Steel (with stainless steel cladding) piping, piping components exposed to treated water	Loss of material due to general (only after cladding degradation), pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no steel with stainless steel cladding piping or piping components exposed to treated water in the Auxiliary Systems.
3.3.1-027	Stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel heat exchanger tubes with a heat transfer function exposed to treated water in the Auxiliary Systems.
3.3.1-028	Not applicable. This line item only applies to PWRs.				
3.3.1-030	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no concrete components exposed to raw water in the Auxiliary Systems.
3.3.1-030a	Fiberglass, HDPE piping, piping components exposed to raw water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no fiberglass or HDPE piping, or piping components exposed to raw water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. This line is also applied to heat exchanger components. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage of copper alloy piping, piping components, and heat exchanger components exposed to raw water.
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. This line item is also applied to heat exchanger components. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage of steel piping, piping components, and heat exchanger components exposed to raw water.
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.2.3.11) AMP is used to manage loss of material and flow blockage of copper alloy and steel heat exchanger components exposed to raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-040	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Consistent with NUREG-2191. This line is also applied to heat exchanger components. The Open-Cycle Cooling Water System (B.2.3.11) AMP is used to manage loss of material and flow blockage in stainless steel and carbon steel with stainless steel cladding piping, piping components, and heat exchanger components exposed to raw water.
3.3.1-042	Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water, raw water (potable), treated water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water (B.2.3.11) AMP is used to manage reduction of heat transfer for copper alloy and stainless steel heat exchanger tubes exposed to raw water.
3.3.1-043	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel piping or piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Auxiliary Systems.
3.3.1-044	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage cracking of stainless steel heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F) in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-045	Steel piping, piping components, tanks exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. This line item has also been applied to heat exchanger components. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage the loss of material of steel piping, piping components, and heat exchanger components exposed to closed-cycle cooling water.
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.2.3.12) AMP is used to manage loss of material of steel and copper alloy heat exchanger components, piping, and piping components exposed to closed-cycle cooling water. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of the diesel fire pump heat exchanger components.
3.3.1-047	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage loss of material of stainless steel heat exchanger components exposed to closed-cycle cooling water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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 or piping components exposed to closed-cycle cooling water in the Auxiliary Systems.
3.3.1-049	Stainless steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage loss of material of stainless steel piping and piping components exposed to closed-cycle cooling water.
3.3.1-050	Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. The Closed Treated Water Systems (B.2.3.12) AMP is used to manage reduction of heat transfer of steel and copper alloy heat exchanger tubes exposed to closed-cycle cooling water. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage reduction of heat transfer of the diesel fire pump heat exchanger tubes.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-051	Boraflex spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity due to boraflex degradation	AMP XI.M22, "Boraflex Monitoring"	No	Not applicable. There are no credited boraflex components in the Auxiliary Systems.
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.2.3.13) AMP is used to manage steel cranes: rails, bridges, structural members, refueling platform, or structural components exposed to air indoor uncontrolled. This line item is used to evaluate structural items associated with the Cranes, Heavy Loads, Rigging System in Section 3.5.
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. This line item is also applied to heat exchanger components. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of steel piping, piping components, and heat exchanger components exposed to condensation.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
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.2.3.15) AMP is used to manage hardening, loss of strength, and shrinkage of elastomer fire barriers exposed to air indoor uncontrolled. This line item is used to evaluate fire barrier penetration seals associated with the Fire Protection Barriers Commodity Group in Section 3.5.
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.2.3.15) AMP is used to manage loss of material of steel halon fire suppression system piping and piping components exposed to air indoor uncontrolled.
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.2.3.15) AMP is used to manage loss of material of steel fire rated doors exposed to air. This line item is used to evaluate fire rated doors for various structures and commodity groups in Section 3.5.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-060	Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M26, "Fire Protection," and AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) and Structures Monitoring (B.2.3.33) AMPs are used to manage cracking and loss of material of reinforced concrete structural fire barriers exposed to air indoor uncontrolled and air outdoor. This line item is used to evaluate reinforced concrete for various structures in Section 3.5.
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 exception. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage of steel fire hydrants exposed to raw water. For fire hydrants exposed to outdoor air, the Fire Water System (B.2.3.16) AMP is used to manage loss of material.
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 exception. This line item is also applied to heat exchanger components. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage of steel and copper alloy piping, piping components, and heat exchanger components exposed to raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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 or piping components exposed to raw water or treated water in the FIR System.
3.3.1-066	Stainless steel piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exception. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage of stainless steel piping and piping components exposed to raw water.
3.3.1-069	Copper alloy piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception for the Fuel Oil Chemistry (B.2.3.18) AMP. The Fuel Oil Chemistry (B.2.3.18) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy piping and piping components exposed to fuel oil.
3.3.1-070	Steel piping, piping components, tanks exposed to fuel oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M30, "Fuel Oil Chemistry," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception with the Fuel Oil Chemistry (B.2.3.18) AMP. The Fuel Oil Chemistry (B.2.3.18) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping, piping components, and tanks exposed to fuel oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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," and AMP XI.M32, "One-Time Inspection," or AMP XI.M30, "Fuel Oil Chemistry"	No	Consistent with NUREG-2191 with exception with the Fuel Oil Chemistry (B.2.3.18) AMP. The Fuel Oil Chemistry (B.2.3.18) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping and piping components exposed to fuel oil.
3.3.1-072	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water, raw water (potable), waste water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. The Selective Leaching (B.2.3.21) AMP is used to manage loss of material of gray cast iron, ductile iron, and copper alloy >15% Zn piping, piping components, and heat exchanger components exposed to raw water, treated water, closed-cycle cooling water, soil, and waste water.
3.3.1-073	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to air – outdoor	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no concrete or cementitious piping or piping components exposed to outdoor air in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-076	Elastomer piping, piping components, ducting, ducting components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage hardening or loss of strength of elastomer piping, piping components, ducting and components exposed to air indoor uncontrolled.
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.2.3.23) AMP is used to manage loss of material of steel external surfaces exposed to air indoor uncontrolled, condensation, and air outdoor.
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.2.3.23) AMP is used to manage loss of material of steel heat exchanger components, piping, and piping components exposed to air indoor uncontrolled and air outdoor. This line item is also applied to components in the ESF.
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.2.3.23) AMP is used to manage loss of material of elastomer piping components, ducting and components exposed to air indoor uncontrolled.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-083	Stainless steel diesel engine exhaust piping, piping components exposed to diesel exhaust	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no stainless steel diesel engine exhaust piping, piping components exposed to diesel exhaust in the Auxiliary Systems.
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.2.3.24) AMP is used to manage flow blockage and hardening or loss of strength for elastomer piping, piping components, ducting and components exposed to indoor uncontrolled air, condensation, treated water, gas, fuel oil, waste water, or raw water. This line item is also applied to components in the S&PC Systems.
3.3.1-088	Steel; stainless steel piping, piping components, diesel engine exhaust exposed to raw water (potable), diesel exhaust	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only for raw water (potable) environment)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) is used to manage loss of material of steel components exposed to diesel exhaust and raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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	Consistent with NUREG-2191 with exception. The Fire Water System (B.2.3.16) AMP is used to manage loss of material of steel piping and piping components exposed to condensation.
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.2.3.24) AMP is used to manage loss of material of steel ducting and components exposed to condensation.
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.2.3.24) AMP is used to manage loss of material and flow blockage of steel piping, piping components and heat exchangers exposed to waste water. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of the steel drip pan in the SLC System.
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.2.3.24) AMP is used to manage loss of material of copper alloy piping and piping components exposed to raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-094	Stainless steel ducting, ducting components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel ducting and components exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.3.2.2.4.
3.3.1-094a	Stainless steel ducting, ducting components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. This line item is also applied to HVAC closure bolting. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of stainless steel ducting, ducting components, and HVAC closure bolting exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.3.2.2.3.
3.3.1-095	Copper alloy, stainless steel, nickel alloy piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material and flow blockage of stainless steel piping, piping components, and tanks exposed to waste water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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.2.3.24) AMP is used to manage loss of material of elastomer piping, piping components, ducting and components exposed to raw water, waste water, treated water, air indoor uncontrolled, or condensation.
3.3.1-096a	Steel, aluminum, copper alloy, stainless steel, titanium heat exchanger tubes internal to components exposed to air, condensation (external)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) is used to manage reduction of heat transfer of copper alloy heat exchanger components exposed to air indoor uncontrolled.
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	Not applicable. There are no steel heat exchanger components exposed to external condensation within the Auxiliary Systems.
3.3.1-097	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. This line item is also applied to heat exchanger components. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping, piping components, and heat exchanger components exposed to lubricating oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. This line item is also applied to pump casing components. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel heat exchanger components exposed to lubricating oil. This line item is also applied to components in the ESF Systems.
3.3.1-099	Copper alloy, aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. This line item is also applied to heat exchanger components. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy piping, piping components, and heat exchanger components exposed to lubricating oil.
3.3.1-100	Stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping and piping components exposed to lubricating oil. This line item is also applied to components in the Reactor Vessel Internals, Reactor Coolant System, and ESF Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	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," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer of aluminum heat exchanger fins exposed to lubricating oil.
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.2.3.26) AMP is used to manage reduction of neutron-absorbing capacity, change in dimensions and loss of material due to effects of SFP environment. This line item is used to evaluate the fuel storage racks neutron absorbing sheets in Section 3.5.
3.3.1-103	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to soil, concrete	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, or piping components exposed to soil or concrete in the Auxiliary Systems.
3.3.1-104	High-density polyethylene (HDPE), fiberglass piping, piping components exposed to soil, concrete	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no HDPE or fiberglass piping, or piping components exposed to soil or concrete in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-107	Stainless steel, nickel alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no stainless steel or nickel alloy piping or piping components exposed to soil or concrete in the Auxiliary Systems.
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	Not applicable. There are no titanium, super austenitic, copper alloy, stainless steel, or nickel alloy piping or piping components exposed to soil or concrete in the Auxiliary Systems.
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. Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage loss of material of steel piping, piping components, and closure bolting exposed to soil or concrete.
3.3.1-110	Stainless steel, nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M7, "BWR Stress Corrosion Cracking," and AMP XI.M2, "Water Chemistry"	No	Not used. There are no stainless steel or nickel alloy components within the scope of the BWR Stress Corrosion Cracking (B.2.3.5) AMP in the Auxiliary Systems. Cracking of stainless steel components exposed to treated water >93°C (>200°F) is addressed by line items 3.3.1-020 and 3.3.1-244.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-111	Steel structural steel exposed to air – indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Not used. Structural steel is addressed as part of structural items in Section 3.5.
3.3.1-112	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Consistent with NUREG-2191. There are no aging effects that require management for steel piping and piping components exposed to concrete that are not subject to wetting. Further evaluation is documented in Section 3.3.2.2.9.
3.3.1-113	Aluminum piping, piping components exposed to gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for aluminum piping and piping components exposed to gas.
3.3.1-114	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. This item also applies to heat exchangers. There are no aging effects that require management for copper piping and piping components exposed to gas, air, or condensation. Ammonia-based compounds cannot accumulate inside of piping and piping components, so cracking is not an applicable aging effect for internal surfaces. Cracking in copper alloys >15% Zn due to exposure to ammonia-based compounds is addressed in item 3.4.1-106.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-115	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. There are no copper alloy piping or piping components exposed to air with borated water leakage in the Auxiliary Systems.
3.3.1-116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for galvanized steel components exposed to air – indoor uncontrolled.
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. There are no aging effects that require management for glass piping elements exposed to air indoor uncontrolled, air outdoor, raw water, Closed-Cycle Cooling Water (CCCW), fuel oil, lubricating oil, or treated water. This line item is also used to evaluate door view ports in Section 3.5 for various buildings. This line item is also applied to components in the ESF Systems.
3.3.1-119	Nickel alloy, PVC, glass piping, piping components exposed to air with borated water leakage, air – indoor uncontrolled, condensation, waste water, raw water (potable)	None	None	No	Consistent with NUREG-2191 There are no aging effects that require management for polyvinyl chloride (plastic) (PVC) or glass piping and piping components exposed to air indoor uncontrolled or waste water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-120	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for stainless steel piping or piping components exposed to gas.
3.3.1-121	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. There are no aging effects that require management for steel piping and piping components exposed to gas or indoor controlled air. This line item is also applied to components in the Reactor Vessels, Internals, and Reactor Coolant System.
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 components in the Auxiliary Systems.
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 (B.2.3.11)," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-124	Stainless steel, steel (with stainless steel or nickel alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water >60°C (>140°F), treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel spent fuel storage racks exposed to treated water >60°C (>140°F). This line item is used to evaluate structural items in Section 3.5.
3.3.1-125	Stainless steel, steel (with stainless steel cladding), nickel alloy spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel spent fuel storage racks and spent fuel pool gates exposed to treated water. This line item is used to evaluate structural items in Section 3.5.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	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	Consistent with NUREG-2191 with exception for the Fire Water System (B.2.3.16) AMP. The Flow-Accelerated Corrosion (B.2.3.9), Open-Cycle Cooling Water System (B.2.3.11), Fire Water System (B.2.3.16) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMPs are used to manage wall thinning of metallic components exposed to raw water and treated water.
3.3.1-127	Metallic piping, piping components, tanks exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.3.2.2.7)	Consistent with NUREG-2191 with exception for the Fire Water System (B.2.3.16) AMP. This also applies to heat exchangers. Based on plant-specific OE, recurring internal corrosion is an applicable effect for steel components in raw water systems that contain water from the Mississippi River. The Open-Cycle Cooling Water System (B.2.3.11), Fire Water System (B.2.3.16) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMPs are used to manage loss of material due to recurring internal corrosion aging effect for steel piping, piping components, and heat exchanger components exposed to raw water. Further evaluation is documented in Section 3.3.2.2.7.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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 tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems.
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 exception. The Fire Water System (B.2.3.16) AMP is used to manage loss of material and flow blockage in metallic sprinklers exposed to raw water, air indoor uncontrolled, air outdoor, and condensation.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-131	Steel, stainless steel, copper alloy, aluminum piping, piping components exposed to air, condensation	Flow blockage due to fouling	AMP XI.M27, "Fire Water System"	No	Consistent with NUREG-2191 with exception for the Fire Water System (B.2.3.16) AMP. The Fire Water System (B.2.3.16) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMPs are used to manage flow blockage in steel, stainless steel, and copper alloy piping and piping components exposed to condensation. The Fire Protection (B.2.3.15) AMP is used to manage flow blockage of stainless steel spray nozzles exposed to condensation in the halon system. This line item is also applied to components in the ESF Systems.
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.2.3.23) AMP is used to manage loss of material of insulated steel piping and piping components exposed to air or condensation.
3.3.1-133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no HDPE underground piping or piping components included in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-134	Steel, stainless steel, copper alloy piping, piping components, and heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of non GL 89-13 steel, stainless steel and copper alloy piping, piping components, and heat exchanger components exposed to raw water.
3.3.1-135	Steel, stainless steel pump casings exposed to waste water environment	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of steel pump casings exposed to waste water in the Auxiliary Systems.
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 exception. This line item is applied to steel piping, piping components, and heat exchanger components. The Fire Water System (B.2.3.16) AMP is used to manage loss of material of steel piping, piping components, and heat exchanger components exposed to air indoor uncontrolled and air outdoor.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-137	Steel, stainless steel, aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water, raw water, waste water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems.
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.2.3.28) AMP is used to manage loss of coating or lining integrity for any material with a coating and loss of material and cracking of cementitious coatings.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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 with exception for the Fire Water System (B.2.3.16) AMP. The Fire Water System (B.2.3.16), Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24), and Open-Cycle Cooling Water System (B.2.3.11) AMPs are used to manage loss of material of internally coated steel piping, piping components, and heat exchanger components exposed to raw water and treated water.
3.3.1-140	Gray cast iron, ductile iron piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	The Selective Leaching (B.2.3.21) AMP is used to manage loss of material of internally coated cast iron piping and piping components exposed to raw water or waste water.
3.3.1-142	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to fuel oil, lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water and waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of material of steel closure bolting exposed to waste water or raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-144	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage cracking of steel piping and piping components exposed to soil. The only component exposed to concrete that is susceptible to cracking is the SLC tank, which is addressed by item 3.3.1-230.
3.3.1-145	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage cracking of stainless steel closure bolting exposed to air indoor uncontrolled and air outdoor.
3.3.1-146	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Not applicable. There are no underground stainless steel components in the Auxiliary Systems. Further evaluation is document in Section 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	Not applicable. There are no nickel alloy or nickel alloy clad piping or piping components exposed to closed-cycle cooling water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
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 and piping components exposed to outdoor air in the Auxiliary Systems.
3.3.1-150	Fiberglass piping, piping components, ducting, ducting components exposed to air	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking, blistering, and loss of material of fiberglass piping components exposed to air indoor uncontrolled. This item is also used to manage cracking and loss of material in fiberglass electrical enclosures in the Hangers and Supports Commodity Group evaluated in Section 3.5.
3.3.1-151	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage reduction in heat transfer in copper alloy and aluminum heat exchanger components exposed to condensation.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-155	Stainless steel piping, piping components, and tanks exposed to waste water >60°C (>140°F)	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage cracking of stainless steel piping and piping components exposed to waste water >60°C (>140°F).
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 exception for the Fire Water System (B.2.3.16) AMP. The Fire Water System (B.2.3.16) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMPs are used to manage loss of material of steel piping and piping components exposed to outdoor air.
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 components exposed to raw water in the 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 components exposed to air internally in the Auxiliary Systems

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, raw water, waste water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M21A, "Closed Treated Water Systems," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 with exception for the Fire Water System (B.2.3.16) AMP. The Open-Cycle Cooling Water System (B.2.3.11), Closed Treated Water Systems (B.2.3.12) and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMPs are used to manage cracking in copper alloy >15% Zn components exposed to closed-cycle cooling water or raw water. Additionally, the Fire Water System (B.2.3.16) AMP is used to manage cracking in copper alloy components exposed to raw water in the FIR System. This line item is also applied to components in the S&PC Systems.
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	Not used. Copper alloy heat exchangers exposed to air are included under item 3.3.1-151.
3.3.1-166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no copper alloy components exposed to concrete in the Auxiliary Systems.
3.3.1-167	Zinc piping components exposed to air-indoor controlled, air – indoor uncontrolled	None	None	No	Not applicable. There are no zinc components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-169	Steel, copper alloy piping, piping components exposed to steam	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in copper alloy piping and piping components exposed to treated water.
3.3.1-170	Stainless steel piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material in stainless steel piping and piping components exposed to treated water. This item is used for components exposed to wet steam, which is considered to be treated water.
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 components in the Auxiliary Systems exposed to outdoor air.
3.3.1-175	Fiberglass piping, piping components, tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage cracking, blistering, and loss of material of fiberglass piping and piping components exposed to treated water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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 used. Loss of material of fiberglass piping and piping components is addressed by item 3.3.1-175.
3.3.1-177	Fiberglass piping, piping components exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no fiberglass piping or piping components exposed to soil in the Auxiliary Systems.
3.3.1-178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not applicable. There are no fiberglass piping or piping components exposed to concrete in the Auxiliary Systems.
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. The Fire Protection (B.2.3.15) and Masonry Walls (B.2.3.32) AMPs are used to manage cracking and loss of material of masonry walls that are structural fire barriers exposed to air indoor uncontrolled. This line item is used to evaluate fire rated masonry block walls in Section 3.5.
3.3.1-181	Titanium piping, piping components exposed to condensation	None	None	No	Not applicable. There are no titanium piping or piping components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not used. Non-metallic thermal insulation is addressed by item 3.2.1-087.
3.3.1-184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no PVC components in the Auxiliary Systems exposed to concrete.
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 in the 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 (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no aluminum tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems. Further evaluation is documented in Section 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 Program (AMP)/TLAA	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 (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of aluminum piping components exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.3.2.2.8.
3.3.1-192	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no aluminum underground piping, piping components, or tanks in the Auxiliary Systems. Further evaluation is documented in Section 3.3.2.2.8.
3.3.1-193	Steel components exposed to treated water, raw water, raw water (potable), waste water	Long-term loss of material due to general corrosion	AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage long-term loss of material of steel components exposed to treated water, raw water, and waste water.
3.3.1-194	PVC piping, piping components, and tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no PVC piping or piping components in the Auxiliary Systems exposed to soil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
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 exception. The Fire Water System (B.2.3.16) AMP is used to manage flow blockage of the Fire Water System (B.2.3.16) cement lined cast iron piping exposed to raw water. Cracking, loss of material, and loss of coating or lining integrity of the cement lined Fire Water System (B.2.3.16) piping is addressed in item 3.3.1-138.
3.3.1-196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering; flow blockage due to fouling (raw water only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no HDPE piping or piping components in the Auxiliary Systems.
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.2.3.23) AMP is used to manage loss of material of metallic FIR System piping with a leakage boundary intended function exposed to air indoor uncontrolled.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-198	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a leakage boundary (spatial) or structural integrity (attached) intended function	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC (all metallic materials except aluminum; in liquid environments only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not used. There is metallic piping and piping components with only a leakage boundary intended function in the FIR System, but internal surfaces of these components are managed by the Fire Water System (B.2.3.16) AMP.
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.2.3.13) AMP is used to manage loss of preload, loss of material of steel structural bolting exposed to air indoor uncontrolled. This line item is used to evaluate structural items associated with the Cranes, Heavy loads, Rigging System in Section 3.5.
3.3.1-202	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Not applicable. The only component exposed to concrete that is susceptible to cracking is the SLC tank, which is addressed by item 3.3.1-230. Further evaluation is documented in Section 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 Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-203	Stainless steel; steel with stainless steel cladding, nickel alloy piping, piping components, heat exchanger components, tanks exposed to treated water, sodium pentaborate solution	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping, piping components, and heat exchanger components exposed to treated water or sodium pentaborate solution.
3.3.1-205	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of insulated stainless steel piping, piping components exposed to condensation. Further evaluation is documented in Section 3.3.2.2.3.
3.3.1-207	Stainless steel, copper alloy, titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no stainless steel or copper alloy heat exchanger tubes exposed to raw water in the Auxiliary System not covered by GL 89-13 that need to be managed for reduction of heat transfer. There are no titanium heat exchanger tubes in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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 or cementitious piping or piping components exposed to raw water in systems not within the scope of the Fire Water System (B.2.3.16) AMP. The Fire System cement lined cast iron piping exposed to raw water is addressed in items 3.3.1-195 and 3.3.1-138.
3.3.1-210	HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking, blistering; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no HDPE piping or piping components in the Auxiliary Systems.
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 piping or piping components exposed to soil in the 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 in the Auxiliary Systems.
3.3.1-216	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no stainless steel fire water storage tanks in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-218	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion, MIC (water and soil environment only)	AMP XI.M27, "Fire Water System"	No	Not applicable. There are no stainless steel fire water storage tanks in the Auxiliary Systems.
3.3.1-219	Stainless steel piping, piping components exposed to steam	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no stainless steel piping and piping components exposed to steam in the Auxiliary Systems.
3.3.1-222	Stainless steel, nickel alloy tanks exposed to air, condensation (internal/external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel piping, piping components, and tanks exposed to air indoor uncontrolled or condensation. Further evaluation is documented in Section 3.3.2.2.4.
3.3.1-223	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no underground aluminum piping or piping components, or tanks in the Auxiliary Systems. Further evaluation is documented in Section 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 Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-226	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems.
3.3.1-227	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems. Further evaluation is documented in Section 3.3.2.2.10.
3.3.1-228	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems. Further evaluation is documented in Section 3.3.2.2.4.
3.3.1-229	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-230	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	This item is used for the stainless steel SLC tank. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of the stainless steel SLC tank bottom exposed to concrete.
3.3.1-231	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Not applicable. There are no tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP in the Auxiliary Systems. Further evaluation is documented in Section 3.3.2.2.3.
3.3.1-232	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of insulated stainless steel piping and piping components exposed to condensation. Further evaluation is documented in Section 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 Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-233	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. There are no insulated aluminum piping or piping components in the Auxiliary Systems.
3.3.1-234	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of aluminum piping components exposed to air indoor uncontrolled. Further evaluation is documented in Section 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 Program (AMP)/TLAA**	**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.2.3.14) AMP is used to manage loss of material of metallic piping and piping components exposed to an internal dry air environment. This line item is also applied to components in the Reactor Vessels, Internals, and Reactor Coolant, ESF, and S&PC Systems.
3.3.1-236	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no titanium components in the 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 components in the 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 components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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 components in the 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 (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no aluminum heat exchanger components exposed to waste water in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.3.1-241	Stainless steel, nickel alloy heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel heat exchanger components exposed to air indoor uncontrolled. Further evaluation is documented in Section 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 (SRP-SLR Section 3.3.2.2.10)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of aluminum heat exchanger components exposed to air. Further evaluation is documented in Section 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 Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-244	Stainless steel, nickel alloy piping, piping components exposed to treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line is also applied to heat exchanger components. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel piping, piping components, and heat exchanger components exposed to treated water >60°C (>140°F).
3.3.1-245	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no insulated aluminum piping or piping components in the Auxiliary Systems.
3.3.1-246	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Not applicable. There are no stainless steel underground components in the Auxiliary Systems. Further evaluation is document in Section 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 Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-247	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. There are no aluminum piping or piping components exposed to raw water or waste water in the Auxiliary Systems.
3.3.1-248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not used. There are no aluminum piping, piping components, tanks exposed to air with borated water leakage in Auxiliary Systems.
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. This item is also applied to piping and piping components. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of steel piping, piping components, and heat exchanger components exposed to air indoor uncontrolled.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-250	Steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M32, "One-Time Inspection"	No	Not applicable. There is no reactor coolant pump oil collection system at MNGP.
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 or piping components exposed to soil or concrete in the Auxiliary Systems.
3.3.1-253	PVC piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water only)	AMP XI.M20, "Open-Cycle Cooling Water System," AMP XI.M27, "Fire Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 with exception for the Fire Water System (B.2.3.16) AMP. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP and Fire Water System (B.2.3.16) AMP are used to manage loss of material of PVC piping and piping components exposed to treated water and raw water.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**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 (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of aluminum heat exchanger components exposed to air indoor uncontrolled. Further evaluation is documented in Section 3.3.2.2.8.
3.3.1-255	Any material fire damper assemblies exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC; hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) AMP is used to manage loss of material of steel fire damper housings exposed to air indoor uncontrolled. This line item is used to evaluate structural items in Section 3.5.
3.3.1-257	Steel, stainless steel, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer of steel and copper alloy heat exchanger components exposed to lubricating oil.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage flow blockage in steel piping and piping components exposed to waste water.
3.3.1-259	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no aluminum piping or piping components exposed to raw water in the Auxiliary Systems.
3.3.1-260	Metallic HVAC closure bolting exposed to air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material and loss of preload of metallic HVAC bolting exposed to air indoor controlled and air indoor uncontrolled.
3.3.1-261	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water, raw water	Cracking due to SCC	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Program (AMP)/TLAA	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 components in the 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	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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) and External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMPs are used to manage hardening or loss of strength, loss of material, and cracking of polymeric piping and piping components exposed to air indoor uncontrolled, raw water, or treated water
3.3.1-265	Steel heat exchanger radiator tubes exposed to fuel oil	Reduction of heat transfer due to fouling	XI.M30, “Fuel Oil Chemistry,” and XI.M32, “One-Time Inspection”	No	Not applicable. There are no steel heat exchanger radiator tubes exposed to fuel oil in the Auxiliary Systems.
3.3.1-266	Steel heat exchanger radiator 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 radiator tubes exposed to fuel oil in the Auxiliary Systems.

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3.1-267	Subliming compound fireproofing/fire barriers (Thermolag ®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air	Loss of material, change in material properties, cracking, delamination, and separation	AMP XI.M26, "Fire Protection"	No	Not applicable. There are no subliming compound fireproofing/fire barriers in the Auxiliary Systems.
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, change in material properties, cracking, delamination, and separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) AMP is used to manage loss of material, change in material properties, cracking, delamination, and separation for cementitious coating fireproofing/fire barriers/HELB barriers exposed to air indoor uncontrolled. This line item is used to evaluate structural items in Section 3.5.
3.3.1-269	Silicate fireproofing/fire barriers (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials) exposed to air	Loss of material, change in material properties, cracking, delamination, and separation	AMP XI.M26, "Fire Protection"	No	Consistent with NUREG-2191. The Fire Protection (B.2.3.15) AMP is used to manage loss of material and change in material properties of thermal fiber exposed to air indoor uncontrolled. This line item is used to evaluate structural items in Section 3.5.

Table 3.3.2-1: Alternate Nitrogen – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (MSIV Accumulators)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Accumulator (MSIV Accumulators)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Accumulator (MSIV Accumulators)	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Hoses	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Hoses	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Hoses	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-1: Alternate Nitrogen – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-1: Alternate Nitrogen – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.3.2-2: Chemistry Sampling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Heat Exchanger - (Sampler Chillers/Coolers) Shell Side components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C
Heat Exchanger - (Sampler Chillers/Coolers) Shell Side components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	C
Heat Exchanger - (Sampler Chillers/Coolers) Shell Side components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-111	3.3.1-203	A
Heat Exchanger - (Sampler Chillers/Coolers) Shell Side components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-111	3.3.1-203	B

Table 3.3.2-2: Chemistry Sampling – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3.1-244	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.A-773	3.3.1-244	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A

Table 3.3.2-2: Chemistry Sampling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3.1-244	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.A-773	3.3.1-244	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3.1-076	A
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3.1-082	A
Expansion Joints	Leakage Boundary	Elastomer	Raw Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-75	3.3.1-085	A

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Expansion Joints	Leakage Boundary	Elastomer	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-76	3.3.1-096	A
Heat Exchanger - (Condenser Water Box) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Condenser Water Box) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Heat Exchanger - (Condenser Water Box) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	C
Heat Exchanger - (Condenser Water Box) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger - (Condenser Water Box) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping Elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping Elements	Leakage Boundary	Glass	Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
Piping Elements	Leakage Boundary	Glass	Waste Water (Internal)	None	None	VII.J.AP-277	3.3.1-119	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	A

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3.1-138	A
Piping, Piping Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-414	3.3.1-139	E, 2
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Pump Casing (Circulating Water Sump Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Circulating Water Sump Pump)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (Circulating Water Sump Pump)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Pump Casing (Circulating Water Sump Pump)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	C

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Circulating Water Sump Pump)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Pump Casing (Circulating Water)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Circulating Water)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (Circulating Water)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Pump Casing (Circulating Water)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	C
Pump Casing (Circulating Water)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Water Box Pump-Down)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Water Box Pump-Down)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (Water Box Pump-Down)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Pump Casing (Water Box Pump-Down)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	C
Pump Casing (Water Box Pump-Down)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Pump Casing (Water Box Scavenging)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Water Box Scavenging)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Water Box Scavenging)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Pump Casing (Water Box Scavenging)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	C
Pump Casing (Water Box Scavenging)	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Tanks (Vacuum Control)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Vacuum Control)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Tanks (Vacuum Control)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Vacuum Control)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Tanks (Water Separator)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Water Separator)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F3.A-778	3.3.1-249	C
Tanks (Water Separator)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Tanks (Water Separator)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Valve Body	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C3.A-400b	3.3.1-127	A
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-473b	3.3.1-160	E, 3

Table 3.3.2-3: Circulating Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3.1-072	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Flow-Accelerated Corrosion (B.2.3.9) program to manage the aging effect of wall thinning. Components affect by this aging effect are located in large diameter piping and other large circulating water components where internal visual inspection, which would detect this aging effect, are routinely performed during refueling outages.

2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material in the base metal of the carbon steel (with internal coating) piping and, piping components exposed to raw water.

3. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Open-Cycle Cooling Water System (B.2.3.11) program to manage cracking in copper alloy with greater than 15% zinc exposed to raw water.

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Accumulator (SCRAM)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Accumulator (SCRAM)	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Accumulator (SCRAM)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Accumulator (SCRAM)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Accumulator (SCRAM)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Accumulator (SCRAM)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Accumulator (SCRAM)	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Accumulator (SCRAM)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Accumulator (SCRAM)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Tubes	Heat Transfer	Carbon Steel	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-204	3.3.1-050	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Tubes	Heat Transfer	Carbon Steel	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.3.25)	VII.E4.A-791	3.3.1-257	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Tubes	Heat Transfer	Carbon Steel	Lubricating Oil (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	VII.E4.A-791	3.3.1-257	A

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (CRD PMP Thrust BRG CLR) Tubes	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3.1-046	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Tubes	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (CRD PMP Thrust BRG CLR) Tubes	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3.1-098	A
Orifice	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Orifice	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Orifice	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Orifice	Throttle	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Orifice	Throttle	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.A-26	3.3.1-055	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-127	3.3.1-097	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-127	3.3.1-097	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal) (added Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15%	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.A-773	3.3.1-244	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E4.A-773	3.3.1-244	B
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.A-26	3.3.1-055	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-127	3.3.1-097	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-127	3.3.1-097	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Piping, Piping Components	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Pump Casing (CRD)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (CRD)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Pump Casing (CRD)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Pump Casing (Lubricating Oil)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-127	3.3.1-097	A
Pump Casing (Lubricating Oil)	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-127	3.3.1-097	A
Speed Increaser Assembly	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Speed Increaser Assembly	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-127	3.3.1-097	A
Speed Increaser Assembly	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-127	3.3.1-097	A
Tanks (SCRAM Discharge)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (SCRAM Discharge)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C
Tanks (SCRAM Discharge)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Valve Body	Pressure Boundary	Aluminum	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.A4.A-451a	3.3.1-189	A
Valve Body	Pressure Boundary	Aluminum	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-763a	3.3.1-234	A
Valve Body	Pressure Boundary	Aluminum	Gas (Internal)	None	None	VII.J.AP-37	3.3.1-113	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-127	3.3.1-097	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-127	3.3.1-097	A

Table 3.3.2-4: Control Rod Drive – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Valve Body	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP is consistent with NUREG 2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP has exceptions to NUREG 2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP is consistent with NUREG 2191 AMP description.

Plant-Specific Notes

None.

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Heat Exchanger - (Demin Water Tank Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C
Heat Exchanger - (Demin Water Tank Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	C
Heat Exchanger - (Demin Water Tank Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.AP-112	3.3.1-020	A
Heat Exchanger - (Demin Water Tank Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.AP-112	3.3.1-020	B

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Demin Water Tank Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-111	3.3.1-203	A
Heat Exchanger - (Demin Water Tank Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-111	3.3.1-203	B
Heat Exchanger - (Demin Water Tank Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C
Heat Exchanger - (Demin Water Tank Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	C
Heat Exchanger - (Demin Water Tank Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-111	3.3.1-203	A
Heat Exchanger - (Demin Water Tank Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-111	3.3.1-203	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-140	3.3.1-022	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E3.AP-32	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-140	3.3.1-022	B
Piping, Piping Components	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3.1-076	A
Piping, Piping Components	Leakage Boundary	Elastomer	Treated Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.A4.AP-101	3.3.1-085	A

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Elastomer	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-76	3.3.1-096	A
Piping, Piping Components	Leakage Boundary	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
Piping, Piping Components	Leakage Boundary	Galvanized Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Galvanized Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Galvanized Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	A

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Polymer	Treated Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Treated Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
Piping, Piping Components	Leakage Boundary	PVC	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-787b	3.3.1-253	E, 1
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 3
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Piping, Piping Components	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3.1-082	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Demin Water Transfer Pump, RO 1st & 2nd Pass Pumps, Chemical Add Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Pump Casing (Demin Water Transfer Pump, RO 1st & 2nd Pass Pumps, Chemical Add Pump)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Pump Casing (Demin Water Transfer Pump, RO 1st & 2nd Pass Pumps, Chemical Add Pump)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Pump Casing (Demin Water Transfer Pump, RO 1st & 2nd Pass Pumps, Chemical Add Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Pump Casing (RO Cleaning Concentrate Pump)	Leakage Boundary	PVC	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-787b	3.3.1-253	E, 1
Pump Casing (RO Cleaning Concentrate Pump)	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
Tanks (Caustic Storage Tank)	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	C

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Caustic Storage Tank)	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	C
Tanks (Caustic Storage Tank)	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	C
Tanks (Caustic Storage Tank)	Leakage Boundary	Polymer	Treated Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	C
Tanks (Caustic Storage Tank)	Leakage Boundary	Polymer	Treated Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	C
Tanks (Caustic Storage Tank)	Leakage Boundary	Polymer	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	C
Tanks (Depth Filter, Softener Tanks, Brine Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Depth Filter, Softener Tanks, Brine Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Tanks (Depth Filter, Softener Tanks, Brine Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.F1.A-416	3.3.1-138	A
Tanks (Depth Filter, Softener Tanks, Brine Tank)	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-414	3.3.1-139	E, 2
Tanks (RO Cleaning Solution Tank, Mixed Bed Deionizer Tanks, Standby Tank)	Leakage Boundary	Fiberglass	Air - Indoor Uncontrolled (External)	Cracking, Blistering, Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-720	3.3.1-150	A
Tanks (RO Cleaning Solution Tank, Mixed Bed Deionizer Tanks, Standby Tank)	Leakage Boundary	Fiberglass	Treated Water (Internal)	Cracking, Blistering, Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-644	3.3.1-175	A
UV Light Housing	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C
UV Light Housing	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	C
UV Light Housing	Leakage Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
UV Light Housing	Leakage Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	C
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3.1-072	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-140	3.3.1-022	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E3.AP-32	3.3.1-072	A

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-140	3.3.1-022	B
Valve Body	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A
Valve Body	Leakage Boundary	PVC	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-787b	3.3.1-253	E, 1
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A

Table 3.3.2-5: Demineralized Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Fire Water System (B.2.3.16) program to manage the loss of material in PVC valve bodies exposed to treated water.

2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material in the base metal of the carbon steel (with internal coating) tanks exposed to raw water.

3. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Flow-Accelerated Corrosion (B.2.3.9) program to wall thinning of the stainless steel piping and piping components exposed to raw water.

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3.1-109	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Electric Heaters (D/G Jacket Coolant Heater Housing)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Electric Heaters (D/G Jacket Coolant Heater Housing)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	A
Expansion Joints	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Expansion Joints	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.A.E-29	3.2.1-044	A
Expansion Joints	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-104	3.3.1-088	A
Flame Arrestor	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Outdoor (External)	None	None	VII.J.AP-144	3.3.1-114	C
Flame Arrestor	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	C

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3.1-076	A
Flexible Connection	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3.1-082	A
Flexible Connection	Pressure Boundary	Elastomer	Condensation (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-504	3.3.1-085	A
Flexible Connection	Pressure Boundary	Elastomer	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-76	3.3.1-096	A
Flexible Connection	Pressure Boundary	Elastomer	Fuel Oil (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H1.A-660	3.3.1-085	A
Heat Exchanger - (After Cooler) Fins	Heat Transfer	Aluminum	Condensation (External)	Reduction of Heat Transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-716	3.3.1-151	C
Heat Exchanger - (After Cooler) Fins	Heat Transfer	Aluminum	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F4.A-771a	3.3.1-242	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (After Cooler) Fins	Heat Transfer	Aluminum	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F4.A-788a	3.3.1-254	A
Heat Exchanger - (After Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (After Cooler) Shell Side Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	C
Heat Exchanger - (After Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	A
Heat Exchanger - (After Cooler) Tube Sheet	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	C
Heat Exchanger - (After Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (After Cooler) Tube Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	C
Heat Exchanger - (After Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3.1-050	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (After Cooler) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Condensation (External)	Reduction of Heat Transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-716	3.3.1-151	A
Heat Exchanger - (After Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3.1-160	A
Heat Exchanger - (After Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3.1-046	C
Heat Exchanger - (After Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3.1-072	C
Heat Exchanger - (After Cooler) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Heat Exchanger - (Jacket Water) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Jacket Water) Shell Side Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	C
Heat Exchanger - (Jacket Water) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	C

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Jacket Water) Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-194	3.3.1-037	C
Heat Exchanger - (Jacket Water) Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.A-532	3.3.1-193	A
Heat Exchanger - (Jacket Water) Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Heat Exchanger - (Jacket Water) Tube Side Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Jacket Water) Tube Side Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-194	3.3.1-037	C
Heat Exchanger - (Jacket Water) Tube Side Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.A-532	3.3.1-193	A
Heat Exchanger - (Jacket Water) Tube Side Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.H2.A-416	3.3.1-138	A
Heat Exchanger - (Jacket Water) Tube Side Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.A-414	3.3.1-139	E, 2

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Jacket Water) Tube Side Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.A-415	3.3.1-140	E, 3
Heat Exchanger - (Jacket Water) Tube Side Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Heat Exchanger - (Jacket Water) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3.1-050	A
Heat Exchanger - (Jacket Water) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-187	3.3.1-042	A
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3.1-160	A
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3.1-046	C
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3.1-072	C
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Heat Exchanger - (Jacket Water) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Heat Exchanger - (Lubricating Oil) Fins	Heat Transfer	Aluminum	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-154	3.3.1-101	C
Heat Exchanger - (Lubricating Oil) Fins	Heat Transfer	Aluminum	Lubricating Oil (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	VII.H2.AP-154	3.3.1-101	C
Heat Exchanger - (Lubricating Oil) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Lubricating Oil) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (Lubricating Oil) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3.1-098	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Lubricating Oil) Tube Sheet	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	C
Heat Exchanger - (Lubricating Oil) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (Lubricating Oil) Tube Sheet	Pressure Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (Lubricating Oil) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Lubricating Oil) Tube Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (Lubricating Oil) Tube Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-131	3.3.1-098	A
Heat Exchanger - (Lubricating Oil) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Reduction of Heat Transfer	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-205	3.3.1-050	A
Heat Exchanger - (Lubricating Oil) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.3.25)	VII.H2.A-791	3.3.1-257	A
Heat Exchanger - (Lubricating Oil) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	VII.H2.A-791	3.3.1-257	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Lubricating Oil) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3.1-046	C
Heat Exchanger - (Lubricating Oil) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3.1-072	C
Heat Exchanger - (Lubricating Oil) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-133	3.3.1-099	C
Heat Exchanger - (Lubricating Oil) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3.1-099	C
Piping Elements	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping Elements	Pressure Boundary	Glass	Air - Outdoor (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping Elements	Pressure Boundary	Glass	Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
Piping Elements	Pressure Boundary	Glass	Fuel Oil (Internal)	None	None	VII.J.AP-49	3.3.1-117	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-780	3.3.1-258	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-24	3.3.1-080	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Outdoor (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-722	3.3.1-157	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-104	3.3.1-088	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Fuel Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-127	3.3.1-097	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3.1-097	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.A-532	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Pressure Boundary	Carbon Steel	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-133	3.3.1-099	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3.1-099	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3.1-046	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3.1-072	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-133	3.3.1-099	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3.1-099	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-136	3.3.1-071	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-136	3.3.1-071	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-138	3.3.1-100	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3.1-100	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-55	3.3.1-040	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.H2.AP-55	3.3.1-040	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Pump Casing (Fuel Oil)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Fuel Oil)	Pressure Boundary	Gray Cast Iron	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Pump Casing (Fuel Oil)	Pressure Boundary	Gray Cast Iron	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Pump Casing (Jacket Water)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Jacket Water)	Pressure Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Jacket Water)	Pressure Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C2.A-50	3.3.1-072	A
Pump Casing (Lubricating Oil)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Lubricating Oil)	Pressure Boundary	Gray Cast Iron	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-127	3.3.1-097	A
Pump Casing (Lubricating Oil)	Pressure Boundary	Gray Cast Iron	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3.1-097	A
Silencer	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-24	3.3.1-080	A
Silencer	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-104	3.3.1-088	A
Strainer (Element)	Filter	Carbon Steel	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Strainer (Element)	Filter	Carbon Steel	Fuel Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Strainer (Element)	Filter	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-127	3.3.1-097	A
Strainer (Element)	Filter	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3.1-097	A
Strainer (Element)	Filter	Stainless Steel	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-136	3.3.1-071	B

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer (Element)	Filter	Stainless Steel	Fuel Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-136	3.3.1-071	A
Tanks (DG Fuel Oil Base Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (DG Fuel Oil Base Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Tanks (DG Fuel Oil Base Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Tanks (DG Fuel Oil Base Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Tanks (DG Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (DG Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Tanks (DG Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Tanks (DG Fuel Oil Day Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (DG Fuel Oil Storage Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Tanks (DG Fuel Oil Storage Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Tanks (DG Fuel Oil Storage Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Tanks (DG Fuel Oil Storage Tank)	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Tanks (DG Fuel Oil Storage Tank)	Pressure Boundary	Carbon Steel	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Tanks (Diesel Fire Pump Day Tank)	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Diesel Fire Pump Day Tank)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Tanks (Diesel Fire Pump Day Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Tanks (Diesel Fire Pump Day Tank)	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (Jacket Water Expansion Tank)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Jacket Water Expansion Tank)	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	A
Tanks (Starting Air)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Starting Air)	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-24	3.3.1-080	A
Valve Body	Leakage Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Valve Body	Leakage Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-24	3.3.1-080	A
Valve Body	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-202	3.3.1-045	A
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.A-26	3.3.1-055	A
Valve Body	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-105	3.3.1-070	B
Valve Body	Pressure Boundary	Carbon Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-105	3.3.1-070	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-127	3.3.1-097	A
Valve Body	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-127	3.3.1-097	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Fuel Oil (External)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H1.AP-132	3.3.1-069	B
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Fuel Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H1.AP-132	3.3.1-069	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H1.AP-132	3.3.1-069	B

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H1.AP-132	3.3.1-069	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.H2.AP-199	3.3.1-046	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3.1-072	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-133	3.3.1-099	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-133	3.3.1-099	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.3.18)	VII.H2.AP-136	3.3.1-071	B
Valve Body	Pressure Boundary	Stainless Steel	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-136	3.3.1-071	A
Valve Body	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.H2.AP-138	3.3.1-100	A
Valve Body	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-138	3.3.1-100	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.H2.AP-209a	3.3.1-004	A

Table 3.3.2-6: Emergency Diesel Generators – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.H2.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Open-Cycle Cooling Water System (B.2.3.11) AMP has been substituted for the Flow-Accelerated Corrosion (B.2.3.9) AMP for wall thinning in raw water environments.

2. The Open-Cycle Cooling Water System (B.2.3.11) AMP is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material in the base metal of the gray cast iron (with internal coating) heat exchanger tube side components exposed to raw water.

3. The Selective Leaching (B.2.3.21) AMP is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage selective leaching in the base metal of the gray cast iron (with internal coating) heat exchanger tube side components exposed to raw water.

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Blower Housing (EFT V-EF-40A)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (EFT V-EF-40A)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (EFT V-EF-40B)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (EFT V-EF-40B)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (EFT V-ERF-14A)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (EFT V-ERF-14A)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Blower Housing (EFT V-ERF-14B)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (EFT V-ERF-14B)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (EFT V-FE-11)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (EFT V-FE-11)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (EFT V-FE-12)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (EFT V-FE-12)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Blower Housing (Inside V-EAC-14A)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (Inside V-EAC-14A)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (Inside V-EAC-14B)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (Inside V-EAC-14B)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Controlled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Controlled (External)	Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Controlled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.A-781a	3.3.1-094a	C
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Controlled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Controlled (External)	Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Chiller (EFT V-EAC-14A)	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (Internal)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.FI.A-419	3.3.1-096a	A
Chiller (EFT V-EAC-14A)	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
Chiller (EFT V-EAC-14A)	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.H.S-454	3.4.1-106	E, 1
Chiller (EFT V-EAC-14A)	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
Chiller (EFT V-EAC-14B)	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (Internal)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.FI.A-419	3.3.1-096a	A
Chiller (EFT V-EAC-14B)	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Chiller (EFT V-EAC-14B)	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.H.S-454	3.4.1-106	E, 1
Chiller (EFT V-EAC-14B)	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air – Indoor Controlled (External)	None	None	VII.J.AP-2	3.3.1-121	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air – Indoor Controlled (Internal)	None	None	VII.J.AP-2	3.3.1-121	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Outdoor (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.A-722	3.3.1-157	A
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3.1-076	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3.1-082	A
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.A-504	3.3.1-085	A
Ducting and Components	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F1.AP-103	3.3.1-096	A
Heat Exchanger (EFT V-EAC-14A Condenser) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger (EFT V-EAC-14A Condenser) Shell Side Components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3.1-038	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger (EFT V-EAC-14A Condenser) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.F1.A-416	3.3.1-138	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tube Side Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.F1.A-414	3.3.1-139	E, 2
Heat Exchanger (EFT V-EAC-14A Condenser) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3.1-042	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	C

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger (EFT V-EAC-14A Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	C
Heat Exchanger (EFT V-EAC-14A Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubesheet	Pressure Boundary	Carbon Steel (with Internal Coating)	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubesheet	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubesheet	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubesheet	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.F1.A-416	3.3.1-138	A
Heat Exchanger (EFT V-EAC-14A Condenser) Tubesheet	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.F1.A-414	3.3.1-139	E, 2

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger (EFT V-EAC-14B Condenser) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger (EFT V-EAC-14B Condenser) Shell Side Components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tube Side Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3.1-042	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger (EFT V-EAC-14B Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	C
Heat Exchanger (EFT V-EAC-14B Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	C
Heat Exchanger (EFT V-EAC-14B Condenser) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tubesheets	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tubesheets	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3.1-038	A
Heat Exchanger (EFT V-EAC-14B Condenser) Tubesheets	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-7: Emergency Filtration Train – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger (EFT V-EAC-14B Condenser) Tubesheets	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-183	3.3.1-038	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F1.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F1.AP-221a	3.3.1-006	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. Although the air environment is external to the chiller tubes / fins, the chiller is located inside the ducting. Therefore, the environment is considered as internal and will be monitored using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP.

2. The Open-Cycle Cooling Water System (B.2.3.11) AMP is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage base metal loss of material.

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (RHR Aux Comp Air Receiver)	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Accumulator (RHR Aux Comp Air Receiver)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-423	3.3.1-142	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3.1-109	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (RHRSW Pump Motor Coolers) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (RHRSW Pump Motor Coolers) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.C1.AP-127	3.3.1-097	C
Heat Exchanger - (RHRSW Pump Motor Coolers) Shell Side Components	Pressure Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-127	3.3.1-097	C
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	Lubricating Oil Analysis (B.2.3.25)	V.D2.EP-78	3.2.1-051	A
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Reduction of Heat Transfer	One-Time Inspection (B.2.3.20)	V.D2.EP-78	3.2.1-051	A
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3.1-042	A
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.C1.AP-133	3.3.1-099	C
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-133	3.3.1-099	C

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (RHRSW Pump Motor Coolers) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Hoses	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Hoses	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Hoses	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Hoses	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Hoses	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Hoses	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Hoses	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Hoses	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Insulated Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Insulated Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Insulated Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-400a	3.3.1-127	A
Insulated Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Insulated Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Insulated Valve Body	Pressure Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Insulated Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Insulated Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Orifice	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Orifice	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Orifice	Throttle	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Orifice	Throttle	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.A-26	3.3.1-055	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-400a	3.3.1-127	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.D.A-26	3.3.1-055	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-400a	3.3.1-127	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Piping, Piping Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3.1-138	A
Piping, Piping Components	Pressure Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-414	3.3.1-139	E, 2
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3.1-072	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Pressure Boundary	Carbon Steel	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Pump Casing (ESW/RHRSW)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (ESW/RHRSW)	Pressure Boundary	Carbon Steel	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (ESW/RHRSW)	Pressure Boundary	Carbon Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Pump Casing (ESW/RHRSW)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Pump Casing (ESW/RHRSW)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (ESW/RHRSW)	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Strainer (Element)	Filter	Carbon Steel	Raw Water (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Strainer (Element)	Filter	Carbon Steel	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Strainer (Element)	Filter	Carbon Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Valve Body	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 1
Valve Body	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A

Table 3.3.2-8: Emergency Service Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3.1-072	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Open-Cycle Cooling Water System (B.2.3.11) program is being substituted for the Flow-Accelerated Corrosion (B.2.3.9) program to manage wall thinning due to erosion in raw water cooling water systems.

2. The Open-Cycle Cooling Water System (B.2.3.11) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material in the base metal of the carbon steel (with internal coating) piping and piping components exposed to raw water.

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-423	3.3.1-142	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Raw Water (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-241	3.3.1-109	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Soil (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Expansion Joints	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Expansion Joints	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-104	3.3.1-088	A
Fire Hydrant	Pressure Boundary	Ductile Iron	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-149	3.3.1-063	B
Fire Hydrant	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-149	3.3.1-063	B
Fire Hydrant	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Fire Hydrant	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-149	3.3.1-063	B
Fire Hydrant	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	A
Fire Hydrant	Pressure Boundary	Ductile Iron	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Fire Hydrant	Pressure Boundary	Ductile Iron	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fire Hydrant	Pressure Boundary	Ductile Iron	Soil (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3.1-072	A
Heat Exchanger - (Diesel Fire Pump) Shell Side Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Heat Exchanger - (Diesel Fire Pump) Shell Side Components	Pressure Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C2.AP-189	3.3.1-046	E, 6
Heat Exchanger - (Diesel Fire Pump) Shell Side Components	Pressure Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C2.A-50	3.3.1-072	C
Heat Exchanger - (Diesel Fire Pump) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C2.A-473a	3.3.1-160	E, 6
Heat Exchanger - (Diesel Fire Pump) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-199	3.3.1-046	E, 6
Heat Exchanger - (Diesel Fire Pump) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3.1-072	C

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Diesel Fire Pump) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (External)	Cracking	Fire Water System (B.2.3.16)	VII.C1.A-473b	3.3.1-160	E, 1
Heat Exchanger - (Diesel Fire Pump) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (External)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Heat Exchanger - (Diesel Fire Pump) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Heat Exchanger - (Diesel Fire Pump) Tube Sheet	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Heat Exchanger - (Diesel Fire Pump) Tube Side Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Heat Exchanger - (Diesel Fire Pump) Tube Side Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	D
Heat Exchanger - (Diesel Fire Pump) Tube Side Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Heat Exchanger - (Diesel Fire Pump) Tube Side Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	D

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Diesel Fire Pump) Tube Side Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	C
Heat Exchanger - (Diesel Fire Pump) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C2.AP-205	3.3.1-050	E, 5
Heat Exchanger - (Diesel Fire Pump) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-437	3.4.1-090	A
Heat Exchanger - (Diesel Fire Pump) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C2.A-473a	3.3.1-160	E, 6
Heat Exchanger - (Diesel Fire Pump) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-199	3.3.1-046	E, 6
Heat Exchanger - (Diesel Fire Pump) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.H2.AP-43	3.3.1-072	C

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Diesel Fire Pump) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Fire Water System (B.2.3.16)	VII.C1.A-473b	3.3.1-160	E, 1
Heat Exchanger - (Diesel Fire Pump) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Heat Exchanger - (Diesel Fire Pump) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Heat Exchanger - (Diesel Fire Pump) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-47	3.3.1-072	A
Hose Station Reels	Structural Support	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Hoses (Pump and Drain Hoses)	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3.1-076	A
Hoses (Pump and Drain Hoses)	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3.1-082	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Hoses (Pump and Drain Hoses)	Leakage Boundary	Elastomer	Raw Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-75	3.3.1-085	A
Hoses (Pump and Drain Hoses)	Leakage Boundary	Elastomer	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-76	3.3.1-096	A
Hoses (Pump and Drain Hoses)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Hoses (Pump and Drain Hoses)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Hoses (Pump and Drain Hoses)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Hoses (Pump and Drain Hoses)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Hoses (Pump and Drain Hoses)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Hoses (Pump and Drain Hoses)	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Orifice	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Orifice	Throttle	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Orifice	Throttle	Stainless Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Piping Elements	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping Elements	Pressure Boundary	Glass	Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.A-649	3.3.1-197	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-400	3.3.1-127	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-797a	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Raw Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	A
Piping, Piping Components	Leakage Boundary	Polymer	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-797b	3.3.1-263	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3.1-058	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3.1-131	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3.1-089	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.H2.AP-104	3.3.1-088	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-400	3.3.1-127	B
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Fire Water System (B.2.3.16)	VII.C1.A-473b	3.3.1-160	E, 1
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3.1-072	A
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-13	3.3.1-116	A
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3.1-131	B
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3.1-089	B
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Galvanized Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Wall Thinning	Fire Water System (B.2.3.16)	VII.C1.A-409	3.3.1-126	E, 7
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Soil (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3.1-072	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Cracking	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.G.A-416	3.3.1-138	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-647	3.3.1-195	B
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.G.A-416	3.3.1-138	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-414	3.3.1-139	E, 2
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Loss of Material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.G.A-416	3.3.1-138	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-415	3.3.1-140	E, 3
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron (with Internal Coating)	Soil (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3.1-072	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Raw Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Raw Water (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Raw Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	A
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Pump Casing (Diesel Driven and Motor Driven Fire Pumps)	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	A
Pump Casing (Fire System Jockey Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.G.A-649	3.3.1-197	A
Pump Casing (Fire System Jockey Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Pump Casing (Fire System Jockey Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Pump Casing (Fire System Jockey Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	A
Spray Nozzles	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Spray Nozzles	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Spray Nozzles	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Spray Nozzles	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Spray Nozzles	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Spray Nozzles	Pressure Boundary	Stainless Steel	Condensation (Internal)	Flow Blockage	Fire Protection (B.2.3.15)	VII.G.A-404	3.3.1-131	E, 4
Spray Nozzles	Pressure Boundary	Stainless Steel	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3.1-131	B
Spray Nozzles	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Spray Nozzles	Spray	Copper Alloy with 15% Zinc or Less	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Spray Nozzles	Spray	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Spray	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Spray	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Spray Nozzles	Spray	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Spray Nozzles	Spray	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Flow Blockage	Fire Protection (B.2.3.15)	VII.G.A-404	3.3.1-131	E, 4

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3.1-131	B
Spray Nozzles	Spray	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Sprinklers	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Sprinklers	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3.1-072	B
Sprinklers	Spray	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with 15% Zinc or Less	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Sprinklers	Spray	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Sprinklers	Spray	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	B
Sprinklers	Spray	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3.1-072	A
Strainer (Element)	Filter	Copper Alloy with 15% Zinc or Less	Raw Water (External)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Strainer (Element)	Filter	Copper Alloy with 15% Zinc or Less	Raw Water (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.G.AP-209a	3.3.1-004	A
Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3.1-131	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Strainer (Element)	Filter	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.AP-221a	3.3.1-006	A
Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Strainer (Element)	Filter	Stainless Steel	Raw Water (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Tanks (Halon)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3.1-058	C
Tanks (Halon)	Pressure Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	C
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3.1-072	A
Valve Body	Leakage Boundary	PVC	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-268	3.3.1-119	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	PVC	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-787b	3.3.1-253	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3.1-131	B
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-143	3.3.1-089	B
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Valve Body	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Outdoor (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-404	3.3.1-131	B
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Condensation (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-403	3.3.1-130	D
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.AP-197	3.3.1-064	B
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3.1-072	A
Valve Body	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Valve Body	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Valve Body	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Ductile Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	A
Valve Body	Pressure Boundary	Ductile Iron	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Valve Body	Pressure Boundary	Ductile Iron	Soil (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3.1-072	A
Valve Body	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Protection (B.2.3.15)	VII.G.AP-150	3.3.1-058	A
Valve Body	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-412	3.3.1-136	D
Valve Body	Pressure Boundary	Gray Cast Iron	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-722	3.3.1-157	B
Valve Body	Pressure Boundary	Gray Cast Iron	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.G.A-532	3.3.1-193	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-33	3.3.1-064	B
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-51	3.3.1-072	A
Valve Body	Pressure Boundary	Gray Cast Iron	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Valve Body	Pressure Boundary	Gray Cast Iron	Soil (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-02	3.3.1-072	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A

Table 3.3.2-9: Fire System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.3.16)	VII.G.A-55	3.3.1-066	B
Valve Body	Pressure Boundary	Carbon Steel	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Valve Body	Pressure Boundary	Ductile Iron	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A
Valve Body	Pressure Boundary	Gray Cast Iron	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.A-425	3.3.1-144	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP has exceptions to NUREG 2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Fire Water System (B.2.3.16) program is being substituted for the Open-Cycle Cooling Water System (B.2.3.11) program to manage cracking in copper alloy with greater than 15% zinc piping with an internal environment of raw water.

2. The Fire Water System (B.2.3.16) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material of the base metal due to general, pitting and crevice corrosion and MIC in the cement lined gray cast iron fire water piping with an internal environment of raw water.

3. The Selective Leaching (B.2.3.21) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material of the base metal due to selective leaching in the cement lined gray cast iron fire water piping with an internal environment of raw water.

4. The Fire Protection (B.2.3.15) program will be used to manage flow blockage in stainless steel halon system spray nozzles with an internal environment of condensation.

5. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component (B.2.3.24) program is being substituted for the Closed Treated Water Systems (B.2.3.12) program to manage the reduction of heat transfer due to fouling in copper alloy with greater than 15% zinc heat exchanger tubes with an internal environment of closed cycle cooling water.

6. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Component (B.2.3.24) program is being substituted for the Closed Treated Water Systems (B.2.3.12) program to manage loss of material and cracking in gray cast iron and copper alloy with greater than 15% zinc heat exchanger components with internal and external environments of closed cycle cooling water.

7. The Fire Water System (B.2.3.16) program is being substituted for the Flow-Accelerated Corrosion (B.2.3.9) program to manage wall thinning due to erosion in gray cast iron piping and piping components exposed to raw water.

Table 3.3.2-10: Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Shell Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.A4.AP-189	3.3.1-046	A
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-439	3.3.1-193	A

Table 3.3.2-10: Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.E4.AP-191	3.3.1-047	A
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-111	3.3.1-203	A
Heat Exchanger - (Fuel Pool Cooling Heat Exchangers) Tube Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-111	3.3.1-203	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-439	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B

Table 3.3.2-10: Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3.1-022	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-140	3.3.1-022	B
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3.1-022	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.A4.AP-32	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-140	3.3.1-022	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3.1-203	A

Table 3.3.2-10: Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-110	3.3.1-203	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209 a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221 a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3.1-203	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-110	3.3.1-203	B
Pump Casings (Fuel Pool Cooling Water Pumps)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casings (Fuel Pool Cooling Water Pumps)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-439	3.3.1-193	A
Pump Casings (Fuel Pool Cooling Water Pumps)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Pump Casings (Fuel Pool Cooling Water Pumps)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Tanks (Skimmer Surge Tanks)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Skimmer Surge Tanks)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-439	3.3.1-193	A

Table 3.3.2-10: Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (Skimmer Surge Tanks)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Tanks (Skimmer Surge Tanks)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Tanks (Skimmer Surge Tanks)	Leakage Boundary	Carbon Steel (with internal coating)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.E4.A-416	3.3.1-138	A
Tanks (Skimmer Surge Tanks)	Leakage Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.A-414	3.3.1-139	E, 1
Tanks (Skimmer Surge Tanks)	Leakage Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.A-414	3.3.1-139	E, 2
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-439	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

Table 3.3.2-10: Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3.1-022	A
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-140	3.3.1-022	B
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-140	3.3.1-022	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.A4.AP-32	3.3.1-072	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-140	3.3.1-022	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3.1-203	A

Table 3.3.2-10: Fuel Pool Cooling and Cleanup – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-110	3.3.1-203	B
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.AP-110	3.3.1-203	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	VII.A4.AP-110	3.3.1-203	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The One-Time Inspection (B.2.3.20) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material in the base metal of the carbon steel (with internal coating) tanks exposed to treated water.

2. The Water Chemistry (B.2.3.2) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material in the base metal of the carbon steel (with internal coating) tanks exposed to treated water.

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Blower Housing (HPCI Room Air Cooling Units)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (HPCI Room Air Cooling Units)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (Reactor Building Main Exhaust Fan)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (Reactor Building Main Exhaust Fan)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (RHR Room Air Cooling Units)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (RHR Room Air Cooling Units)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (Standby DG Room Supply Fan)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Blower Housing (Standby DG Room Supply Fan)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Blower Housing (Turbine Building Operating Floor Air Handling Unit)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Blower Housing (Turbine Building Operating Floor Air Handling Unit)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F1.A-781a	3.3.1-094a	C
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Bolting (HVAC Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.F1.A-794	3.3.1-260	A
Chillers - (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Chillers - (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Chillers - (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-194	3.3.1-037	E, 1

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Chillers - (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (External)	None	None	VII.J.AP-9	3.3.1-114	C
Chillers - (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-473b	3.3.1-160	E, 2
Chillers - (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Chillers - (Reactor Building Chiller Condenser) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Chillers - (Reactor Building Chiller Evaporator) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Chillers - (Reactor Building Chiller Evaporator) Shell Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F2.AP-189	3.3.1-046	A
Chillers - (Reactor Building Chiller Evaporator) Shell Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3.1-160	A
Chillers - (Reactor Building Chiller Evaporator) Shell Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F2.AP-199	3.3.1-046	C
Chillers - (Reactor Building Chiller Evaporator) Shell Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F2.AP-43	3.3.1-072	C
Chillers - (Reactor Building Chiller Evaporator) Shell Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VII.J.AP-9	3.3.1-114	C

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Ducting and Components	HELB barrier	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Ducting and Components	HELB barrier	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Ducting and Components	Flood barrier	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Ducting and Components	Flood barrier	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Ducting and Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Ducting and Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Ducting and Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Ducting and Components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Ducting and Components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Heat Exchanger - (Area Air Cooling Units) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Area Air Cooling Units) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Heat Exchanger - (Area Air Cooling Units) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Area Air Cooling Units) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-473b	3.3.1-160	E, 2
Heat Exchanger - (Area Air Cooling Units) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Heat Exchanger - (Area Air Cooling Units) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Heat Exchanger - (Condensate Storage Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Condensate Storage Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Heat Exchanger - (Condensate Storage Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	C

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Condensate Storage Heat Exchanger) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	D
Heat Exchanger - (Condensate Storage Heat Exchanger) Tube Side Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Condensate Storage Heat Exchanger) Tube Side Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Heat Exchanger - (Condensate Storage Heat Exchanger) Tube Side Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	C
Heat Exchanger - (Condensate Storage Heat Exchanger) Tube Side Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.E.SP-27	3.4.1-033	C
Heat Exchanger - (Condensate Storage Heat Exchanger) Tube Side Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	D
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Fins	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Reduction of Heat Transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-424	3.2.1-081	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Shell Side Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-778	3.3.1-249	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tube Side Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tube Side Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tube Side Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tube Side Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tube Side Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.A-770a	3.3.1-241	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tube Side Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Reduction of Heat Transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-424	3.2.1-081	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3.1-038	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Heat Transfer	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3.1-042	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Heat Transfer	Stainless Steel	Air - Indoor Uncontrolled (External)	Reduction of Heat Transfer	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-424	3.2.1-081	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Heat Transfer	Stainless Steel	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-187	3.3.1-042	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-473b	3.3.1-160	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-179	3.3.1-038	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	V.D2.EP-103b	3.2.1-007	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	V.D2.EP-107a	3.2.1-004	C
Heat Exchanger - (HPCI/RHR/CS Room Air Cooling Unit) Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	C
Heat Exchanger - (Reactor Building Heating Coils) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Reactor Building Heating Coils) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-778	3.3.1-249	C
Heat Exchanger - (Reactor Building Heating Coils) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Reactor Building Heating Coils) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-140	3.3.1-022	C
Heat Exchanger - (Reactor Building Heating Coils) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F1.AP-65	3.3.1-072	A
Heat Exchanger - (Reactor Building Heating Coils) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-140	3.3.1-022	D
Heat Exchanger - (Reactor Building Main Supply HVAC Unit Heating Coil) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Reactor Building Main Supply HVAC Unit Heating Coil) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-778	3.3.1-249	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Reactor Building Main Supply HVAC Unit Heating Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Heat Exchanger - (Reactor Building Main Supply HVAC Unit Heating Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-140	3.3.1-022	C
Heat Exchanger - (Reactor Building Main Supply HVAC Unit Heating Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F1.AP-65	3.3.1-072	A
Heat Exchanger - (Reactor Building Main Supply HVAC Unit Heating Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-140	3.3.1-022	D
Heat Exchanger - (Reactor Building Main Supply HVAC Unit, Cooling Coil) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Reactor Building Main Supply HVAC Unit, Cooling Coil) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-778	3.3.1-249	C
Heat Exchanger - (Reactor Building Main Supply HVAC Unit, Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Heat Exchanger - (Reactor Building Main Supply HVAC Unit, Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3.1-160	A
Heat Exchanger - (Reactor Building Main Supply HVAC Unit, Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F2.AP-199	3.3.1-046	A
Heat Exchanger - (Reactor Building Main Supply HVAC Unit, Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F2.AP-43	3.3.1-072	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Steam Chase Supply Cooling Coil) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Steam Chase Supply Cooling Coil) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.B.E-25	3.2.1-044	A
Heat Exchanger - (Steam Chase Supply Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Heat Exchanger - (Steam Chase Supply Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-473b	3.3.1-160	E, 2
Heat Exchanger - (Steam Chase Supply Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Steam Chase Supply Cooling Coil) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-66	3.3.1-072	A
Heat Exchanger - (Turbine Building Reheaters) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Turbine Building Reheaters) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-778	3.3.1-249	C
Heat Exchanger - (Turbine Building Reheaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C
Heat Exchanger - (Turbine Building Reheaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-140	3.3.1-022	C

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Turbine Building Reheaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F1.AP-65	3.3.1-072	A
Heat Exchanger - (Turbine Building Reheaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-140	3.3.1-022	D
Heat Exchanger - (Unit Heaters) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Unit Heaters) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-778	3.3.1-249	C
Heat Exchanger - (Unit Heaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	C

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Unit Heaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-140	3.3.1-022	C
Heat Exchanger - (Unit Heaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F1.AP-65	3.3.1-072	A
Heat Exchanger - (Unit Heaters) Tube Side Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-140	3.3.1-022	D
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.AP-209a	3.3.1-004	A
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.AP-221a	3.3.1-006	A
Hoses	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Hoses	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Hoses	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A
Hoses	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F2.AP-202	3.3.1-045	A
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Piping, Piping Components	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3.1-049	A
Insulated Piping, Piping Components	Leakage Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.I.A-734b	3.3.1-205	A
Insulated Piping, Piping Components	Leakage Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-761b	3.3.1-232	A
Insulated Pump Casing (Reactor Building Chilled Water Pump)	Leakage Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F2.AP-202	3.3.1-045	A
Insulated Pump Casing (Reactor Building Chilled Water Pump)	Leakage Boundary	Gray Cast Iron	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C2.A-50	3.3.1-072	A
Insulated Pump Casing (Reactor Building Chilled Water Pump)	Leakage Boundary	Gray Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Insulated Valve Body	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F2.AP-202	3.3.1-045	A
Insulated Valve Body	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Valve Body	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3.1-049	A
Insulated Valve Body	Leakage Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.I.A-734b	3.3.1-205	A
Insulated Valve Body	Leakage Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-761b	3.3.1-232	A
Piping Elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping Elements	Leakage Boundary	Glass	Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
Piping Elements	Leakage Boundary	Glass	Treated Water (Internal)	None	None	VII.J.AP-51	3.3.1-117	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Gas (Internal)	None	None	VII.J.AP-6	3.3.1-121	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F2.AP-31	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.A-566	3.3.1-169	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.F2.A-566	3.3.1-169	B
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-473a	3.3.1-160	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F2.AP-199	3.3.1-046	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F2.AP-43	3.3.1-072	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.A-566	3.3.1-169	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C2.AP-32	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.F2.A-566	3.3.1-169	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.AP-221a	3.3.1-006	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3.1-049	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B
Pump Casing (Condensate Return)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Condensate Return)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Pump Casing (Condensate Return)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Pump Casing (Condensate Return)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F2.AP-31	3.3.1-072	A
Pump Casing (Condensate Return)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Tanks (Chilled Water Expansion Tank)	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.F1.AP-202	3.3.1-045	A
Tanks (Chilled Water Expansion Tank)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-26	3.3.1-055	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (Chilled Water Expansion Tank)	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Condensate Return Tanks, Intake/Turbine/Reactor Building)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Condensate Return Tanks, Intake/Turbine/Reactor Building)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.F2.A-26	3.3.1-055	A
Tanks (Condensate Return Tanks, Intake/Turbine/Reactor Building)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Tanks (Condensate Return Tanks, Intake/Turbine/Reactor Building)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	C
Tanks (Condensate Return Tanks, Intake/Turbine/Reactor Building)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Valve Body	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.F2.AP-31	3.3.1-072	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-140	3.3.1-022	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.E.SP-55	3.4.1-033	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-140	3.3.1-022	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.F2.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3.1-049	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.F2.A-567	3.3.1-170	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.F2.A-567	3.3.1-170	B
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A

Table 3.3.2-11: Heating and Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program has been substituted for the Open-Cycle Cooling Water System (B.2.3.11) program and will be used to manage loss of material in carbon steel chiller components exposed to raw water.

2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program has been substituted for the Open-Cycle Cooling Water System (B.2.3.11) program and will be used to manage cracking in copper alloy with greater than 15% zinc chiller components exposed to raw water.

Table 3.3.2-12: Instrument and Service Air – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A

Table 3.3.2-12: Instrument and Service Air – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Piping, Piping Components	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A

Table 3.3.2-12: Instrument and Service Air – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Gas (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Structural Integrity (Attached)	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A

Table 3.3.2-12: Instrument and Service Air – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Structural Integrity (Attached)	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Waste Water (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-423	3.3.1-142	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Waste Water (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Heat Exchanger (Drywell Equip Drain Sump) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger (Drywell Equip Drain Sump) Shell Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3.1-046	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger (Drywell Equip Drain Sump) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger (Drywell Equip Drain Sump) Tube Side Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Heat Exchanger (Drywell Equip Drain Sump) Tube Side Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Orifice	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Orifice	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Orifice	Leakage Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Orifice	Leakage Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Orifice	Throttle	Stainless Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Orifice	Throttle	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Orifice	Throttle	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Concrete (External)	None	None	VII.J.AP-282	3.3.1-112	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Concrete (External)	None	None	VII.J.AP-282	3.3.1-112	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron (with Internal Coating)	Concrete (External)	None	None	VII.J.AP-282	3.3.1-112	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron (with Internal Coating)	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron (with Internal Coating)	Waste Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/linings for in-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.E5.A-416	3.3.1-138	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Gray Cast Iron (with Internal Coating)	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-414	3.3.1-139	E, 1
Piping, Piping Components	Leakage Boundary	Gray Cast Iron (with Internal Coating)	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E5.A-415	3.3.1-140	E, 2
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Concrete (External)	None	None	VII.J.AP-282	3.3.1-112	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3.1-072	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Structural Integrity (Attached)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Pump Casing (DW Equipment Drain Sump/RB Equipment Drain Sump/ TB Equipment Drain Sump/Condensate Drip Tank/DW Floor Drain Sump/Condensate Pump Area Sump/Condensate Backwash/RB Equipment Drain Tank)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (DW Equipment Drain Sump/RB Equipment Drain Sump/ TB Equipment Drain Sump/Condensate Drip Tank/DW Floor Drain Sump/Condensate Pump Area Sump/Condensate Backwash/RB Equipment Drain Tank)	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Pump Casing (DW Equipment Drain Sump/RB Equipment Drain Sump/ TB Equipment Drain Sump/Condensate Drip Tank/DW Floor Drain Sump/Condensate Pump Area Sump/Condensate Backwash/RB Equipment Drain Tank)	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (DW Equipment Drain Sump/RB Equipment Drain Sump/ TB Equipment Drain Sump/Condensate Drip Tank/DW Floor Drain Sump/Condensate Pump Area Sump/Condensate Backwash/RB Equipment Drain Tank)	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3.1-072	A
Pump Casing (RB Floor Drain Sump/RB Floor Drain Tank/TB Floor Drain Sump/ECCS Area Drain)	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (RB Floor Drain Sump/RB Floor Drain Tank/TB Floor Drain Sump/ECCS Area Drain)	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Pump Casing (RB Floor Drain Sump/RB Floor Drain Tank/TB Floor Drain Sump/ECCS Area Drain)	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (RB Floor Drain Sump/RB Floor Drain Tank/TB Floor Drain Sump/ECCS Area Drain)	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Pump Casing (RB Floor Drain Sump/RB Floor Drain Tank/TB Floor Drain Sump/ECCS Area Drain)	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3.1-072	A
Tanks (Air Surge Volume)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Air Surge Volume)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-26	3.3.1-055	A
Tanks (Air Surge Volume)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Tanks (Air Surge Volume)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Tanks (Condensate Backwash Receiving)	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118	3.4.1-002	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Condensate Backwash Receiving)	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Condensate Backwash Receiving)	Holdup and Plateout	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Tanks (Condensate Backwash Receiving)	Holdup and Plateout	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Condensate Backwash Receiving)	Holdup and Plateout	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Tanks (Condensate Backwash Receiving)	Holdup and Plateout	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A
Tanks (Condensate Backwash Receiving)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118	3.4.1-002	A
Tanks (Condensate Backwash Receiving)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Condensate Backwash Receiving)	Leakage Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Tanks (Condensate Backwash Receiving)	Leakage Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Condensate Backwash Receiving)	Leakage Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Tanks (Condensate Backwash Receiving)	Leakage Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A
Tanks (Machine Shop Drain)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118	3.4.1-002	A
Tanks (Machine Shop Drain)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Machine Shop Drain)	Leakage Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118	3.4.1-002	A
Tanks (Machine Shop Drain)	Leakage Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Machine Shop Drain)	Leakage Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Tanks (Machine Shop Drain)	Leakage Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (RB Equipment Drain/Condensate Drip)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (RB Equipment Drain/Condensate Drip)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-26	3.3.1-055	A
Tanks (RB Equipment Drain/Condensate Drip)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Tanks (RB Equipment Drain/Condensate Drip)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Tanks (RB Floor Drain)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118	3.4.1-002	A
Tanks (RB Floor Drain)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (RB Floor Drain)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118	3.4.1-002	A
Tanks (RB Floor Drain)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (RB Floor Drain)	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Tanks (RB Floor Drain)	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Tanks (RB Floor Drain)	Pressure Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Valve Body	Holdup and Plateout	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Holdup and Plateout	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Valve Body	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Valve Body	Leakage Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Valve Body	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.D.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.D.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Valve Body	Pressure Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-278	3.3.1-095	A
Valve Body	Pressure Boundary	Stainless Steel	Waste Water >140 F (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-721	3.3.1-155	A
Valve Body	Structural Integrity (Attached)	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-13: Radwaste Solid and Liquid – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Structural Integrity (Attached)	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Valve Body	Structural Integrity (Attached)	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material of the base metal of the gray cast iron (with internal coating) piping, piping component with an internal environment of waste water.

2. The Selective Leaching (B.2.3.21) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage selective leaching in the base metal of the gray cast iron (with internal coating) piping, piping components with an internal environment of waste water.

Table 3.3.2-14: Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Heat Exchanger - (Drywell Coolers) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (Drywell Coolers) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3.1-046	C
Heat Exchanger - (RB Cooling Water) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (RB Cooling Water) Shell Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-189	3.3.1-046	A
Heat Exchanger - (RB Cooling Water) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-14: Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (RB Cooling Water) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Heat Exchanger - (RB Cooling Water) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3.1-138	A
Heat Exchanger - (RB Cooling Water) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-414	3.3.1-139	E, 1
Hoses	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Hoses	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A

Table 3.3.2-14: Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Insulated Valve Body	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Insulated Valve Body	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Piping Elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping Elements	Leakage Boundary	Glass	Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3.1-046	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

Table 3.3.2-14: Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3.1-046	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C2.AP-221a	3.3.1-006	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3.1-049	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Pump Casing (Reactor Building Cooling Water Pumps)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Reactor Building Cooling Water Pumps)	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-14: Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Chemical Feeder)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Chemical Feeder)	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Tanks (Chemical Feeder)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-26	3.3.1-055	A
Tanks (Reactor Building Cooling Water Surge Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Tanks (Reactor Building Cooling Water Surge Tank)	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Tanks (Reactor Building Cooling Water Surge Tank)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-26	3.3.1-055	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-14: Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3.1-046	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-199	3.3.1-046	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Closed Cycle Cooling Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C2.AP-43	3.3.1-072	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C2.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C2.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-14: Reactor Building Closed Cooling Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.C2.AP-202	3.3.1-045	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material in the base metal of the carbon steel (with internal coating) heat exchanger tube side components exposed to raw water.

Table 3.3.2-15: Reactor Water Cleanup – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Heat Exchanger - (Non-Regenerative) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Non-Regenerative) Shell Side Components	Leakage Boundary	Carbon Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.E3.AP-189	3.3.1-046	A
Heat Exchanger - (Non-Regenerative) Shell Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Heat Exchanger - (Non-Regenerative) Shell Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Non-Regenerative) Shell Side Components	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.3.12)	VII.E3.AP-191	3.3.1-047	A
Heat Exchanger - (Non-Regenerative) Shell Side Components	Leakage Boundary	Stainless Steel	Closed Cycle Cooling Water >140 F (Internal)	Cracking	Closed Treated Water Systems (B.2.3.12)	VII.E3.AP-192	3.3.1-044	A
Heat Exchanger - (Non-Regenerative) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Non-Regenerative) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Heat Exchanger - (Non-Regenerative) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A
Heat Exchanger - (Non-Regenerative) Tube Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Heat Exchanger - (Non-Regenerative) Tube Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Heat Exchanger - (Non-Regenerative) Tube Side Components	Leakage Boundary	Stainless Steel	Treated water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3.1-244	A

Table 3.3.2-15: Reactor Water Cleanup – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Non-Regenerative) Tube Side Components	Leakage Boundary	Stainless Steel	Treated water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.A-773	3.3.1-244	B
Heat Exchanger - (Regenerative) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Regenerative) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Heat Exchanger - (Regenerative) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	C
Heat Exchanger - (Regenerative) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	D
Heat Exchanger - (Regenerative) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-41	3.3.1-080	A
Heat Exchanger - (Regenerative) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Heat Exchanger - (Regenerative) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	C
Heat Exchanger - (Regenerative) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	D
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A

Table 3.3.2-15: Reactor Water Cleanup – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Orifice	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Orifice	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3.1-126	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Orifice	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Orifice	Throttle	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3.1-126	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3.1-126	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.E.S-16	3.4.1-005	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-133	3.3.1-099	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-133	3.3.1-099	A
Piping, Piping Components	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping, Piping Components	Leakage Boundary	Glass	Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-138	3.3.1-100	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-138	3.3.1-100	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3.1-126	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3.1-244	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.A-773	3.3.1-244	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3.1-126	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.E.S-16	3.4.1-005	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VII.E3.A-408	3.3.1-126	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3.1-244	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.A-773	3.3.1-244	B
Pump Casing (Cleanup Recirc Pumps)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Pump Casing (Cleanup Recirc Pumps)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Pump Casing (Cleanup Recirc Pumps)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Pump Casing (Cleanup Recirc Pumps)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.E4.AP-138	3.3.1-100	A
Valve Body	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-138	3.3.1-100	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3.1-244	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.A-773	3.3.1-244	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.A-439	3.3.1-193	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-106	3.3.1-021	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-106	3.3.1-021	B

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

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4-AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E3.AP-110	3.3.1-203	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E3.AP-110	3.3.1-203	B
Valve Body	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E3.A-773	3.3.1-244	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VII.E3.A-773	3.3.1-244	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3.1-076	A
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3.1-082	A
Expansion Joints	Leakage Boundary	Elastomer	Raw Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-75	3.3.1-085	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Expansion Joints	Leakage Boundary	Elastomer	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.AP-76	3.3.1-096	A
Heat Exchanger - (Recirc MG Set Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Recirc MG Set Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VII.C1.AP-127	3.3.1-097	C
Heat Exchanger - (Recirc MG Set Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-127	3.3.1-097	C
Heat Exchanger - (Recirc MG Set Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Heat Exchanger - (Recirc MG Set Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Recirc MG Set Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3.1-138	A
Heat Exchanger - (Recirc MG Set Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-414	3.3.1-139	E, 3
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Hoses	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Hoses	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-400b	3.3.1-127	A
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Insulated Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Insulated Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Insulated Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Insulated Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Insulated Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Insulated Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Insulated Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Insulated Piping, Piping Components	Leakage Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.I.A-734b	3.3.1-205	A
Insulated Piping, Piping Components	Leakage Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-761b	3.3.1-232	A
Insulated Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Insulated Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Insulated Valve Body	Leakage Boundary	Carbon Steel	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Insulated Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Insulated Valve Body	Leakage Boundary	Gray Cast Iron	Condensation (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-405a	3.3.1-132	A
Insulated Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Insulated Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Insulated Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Insulated Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Condensation (External)	None	None	VII.J.AP-144	3.3.1-114	C
Insulated Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Insulated Valve Body	Leakage Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.I.A-734b	3.3.1-205	A
Insulated Valve Body	Leakage Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-761b	3.3.1-232	A
Insulated Valve Body	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping Elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-48	3.3.1-117	A
Piping Elements	Leakage Boundary	Glass	Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-400b	3.3.1-127	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.C1.A-416	3.3.1-138	A
Piping, Piping Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-414	3.3.1-139	E, 3

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-409	3.3.1-126	E, 1
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-400a	3.3.1-127	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 2

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Wall Thinning	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-409	3.3.1-126	E, 2
Pump Casing (Seal Water Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Seal Water Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (Seal Water Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Pump Casing (Seal Water Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Service Water Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Service Water Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (Service Water Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Pump Casing (Service Water Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Pump Casing (Service Water Radiation Monitor Sample Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Service Water Radiation Monitor Sample Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Pump Casing (Service Water Radiation Monitor Sample Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Service Water Radiation Monitor Sample Pump)	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-194	3.3.1-037	A
Valve Body	Pressure Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.3.1-072	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	A
Valve Body	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.AP-196	3.3.1-034	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.C1.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Flow Blockage	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A

Table 3.3.2-16: Service and Seal Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.3.11)	VII.C1.A-54	3.3.1-040	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. Piping with the Leakage Boundary function subject to the wall thinning aging effect are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) instead of the Flow-Accelerated Corrosion (B.2.3.9) program.

2. Piping with the Pressure Boundary function subject to the wall thinning aging effect are managed by the Open-Cycle Cooling Water System (B.2.3.11) instead of the Flow-Accelerated Corrosion (B.2.3.9) program.

3. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP will be used to manage base metal loss of material instead of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP.

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Accumulator (Standby Liquid Control Accumulator)	Pressure Boundary	Carbon Steel (with Internal Coating)	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Accumulator (Standby Liquid Control Accumulator)	Pressure Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VII.E4.A-416	3.3.1-138	A
Accumulator (Standby Liquid Control Accumulator)	Pressure Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E4.A-414	3.3.1-139	E, 4
Accumulator (Standby Liquid Control Accumulator)	Pressure Boundary	Elastomer	Gas (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.A-729	3.3.1-085	A
Accumulator (Standby Liquid Control Accumulator)	Pressure Boundary	Elastomer	Treated Water (External)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-75	3.3.1-085	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Drip Pan	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Drip Pan	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Drip Pan	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E5.AP-281	3.3.1-091	E, 2
Hoses	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-102	3.3.1-076	A
Hoses	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.AP-113	3.3.1-082	A

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Hoses	Leakage Boundary	Elastomer	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-728	3.3.1-085	A
Hoses	Leakage Boundary	Elastomer	Waste Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-728	3.3.1-085	A
Hoses	Leakage Boundary	Elastomer	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-550	3.3.1-096	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-439	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Sodium Pentaborate Solution (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	None	None	G, 1
Piping, Piping Components	Pressure Boundary	Carbon Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	None	None	G, 1
Piping, Piping Components	Pressure Boundary	Carbon Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	None	None	G, 1

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.A4.A-439	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3.1-203	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E2.AP-141	3.3.1-203	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Pump Casing (Standby Liquid Control Pump)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Standby Liquid Control Pump)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Pump Casing (Standby Liquid Control Pump)	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3.1-203	A
Pump Casing (Standby Liquid Control Pump)	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E2.AP-141	3.3.1-203	B
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Concrete (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E5.A-759	3.3.1-230	E, 3
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	C
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3.1-203	A
Tanks (Standby Liquid Control Tank)	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E2.AP-141	3.3.1-203	B

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Standby Liquid Control Test Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Tanks (Standby Liquid Control Test Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.I.A-751b	3.3.1-222	A
Tanks (Standby Liquid Control Test Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	C
Tanks (Standby Liquid Control Test Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E2.A-439	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-106	3.3.1-021	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-106	3.3.1-021	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3.1-203	A
Valve Body	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E2.AP-141	3.3.1-203	B
Valve Body	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VII.E4.AP-209a	3.3.1-004	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-221a	3.3.1-006	A
Valve Body	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E2.AP-141	3.3.1-203	A
Valve Body	Pressure Boundary	Stainless Steel	Sodium Pentaborate Solution (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E2.AP-141	3.3.1-203	B

Table 3.3.2-17: Standby Liquid Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VII.E4.AP-110	3.3.1-203	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VII.E4.AP-110	3.3.1-203	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

G. Environment not in NUREG-2191 for this component and material.

Plant-Specific Notes

1. The Water Chemistry (B.2.3.2) Program manages the aging effects on SLC System components subject to the sodium pentaborate environment by monitoring and controlling SLC poison storage tank treated water chemistry. Aging effects on carbon steel exposed to a sodium pentaborate environment are established using a treated water environment.

2. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) program is being substituted for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program to manage the aging effect applicable to this component type, material, and environment combination.

3. The One-Time Inspection (B.2.3.20) AMP is being substituted for the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP to verify that the aging effect of cracking on the stainless steel base plate of the SLC tank (T-200) has been mitigated. The base plate has experienced cracking, has been replaced, and an epoxy coating applied to the concrete tank pedestal to prevent future cracking as a result of chloride exposure from the concrete.

4. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage the loss of material in the base metal of carbon steel (with internal coating) accumulators exposed to treated water.

Table 3.3.2-18: Wells and Domestic Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VII.I.A-426	3.3.1-145	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VII.I.A-03	3.3.1-012	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VII.I.AP-124	3.3.1-015	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-18: Wells and Domestic Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-271	3.3.1-093	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.G.A-47	3.3.1-072	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-18: Wells and Domestic Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Raw Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.C1.A-51	3.31-072	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Concrete (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VII.I.AP-198	3.3.1-109	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Pump Casing (Turbine Building Normal Waste Sump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Pump Casing (Turbine Building Normal Waste Sump)	Leakage Boundary	Carbon Steel	Waste Water (External)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Pump Casing (Turbine Building Normal Waste Sump)	Leakage Boundary	Carbon Steel	Waste Water (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.E5.A-410	3.3.1-135	A

Table 3.3.2-18: Wells and Domestic Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Turbine Building Normal Waste Sump)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Pump Casing (Turbine Building Normal Waste Sump)	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.C1.A-532	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-270	3.3.1-088	A
Valve Body	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Valve Body	Leakage Boundary	Carbon Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-18: Wells and Domestic Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A
Valve Body	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Leakage Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3.1-072	A
Valve Body	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VII.I.A-77	3.3.1-078	A
Valve Body	Pressure Boundary	Gray Cast Iron	Concrete (External)	None	None	VII.J.AP-282	3.3.1-112	A
Valve Body	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Flow Blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VII.E5.A-785	3.3.1-193	A

Table 3.3.2-18: Wells and Domestic Water – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.AP-281	3.3.1-091	A
Valve Body	Pressure Boundary	Gray Cast Iron	Waste Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VII.E5.A-547	3.3.1-072	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

None.

3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.3.4, *Steam and Power Conversion Systems*, as being subject to AMR. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Condensate Storage (2.3.4.1)
- Condensate and Feedwater (2.3.4.2)
- Main Condenser (2.3.4.3)
- Main Steam (2.3.4.4)
- Off-Gas (2.3.4.5)
- Turbine Generator (2.3.4.6)

3.4.2 Results

Table 3.4.2-1, Condensate Storage – Summary of Aging Management Evaluation

Table 3.4.2-2, Condensate and Feedwater – Summary of Aging Management Evaluation

Table 3.4.2-3, Main Condenser – Summary of Aging Management Evaluation

Table 3.4.2-4, Main Steam – Summary of Aging Management Evaluation

Table 3.4.2-5, Off-Gas – Summary of Aging Management Evaluation

Table 3.4.2-6, Turbine Generator – 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 Storage

Materials

The materials of construction for the CST System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Elastomer
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The CST System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Concrete
- Condensation
- Soil
- Treated Water
- Treated Water >140°F

Due to steam quality, the environment of steam is identified as treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the CST System require management:

- Cracking
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the CST System components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- One-Time Inspection (B.2.3.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.4.2.1.2 Condensate and Feedwater

Materials

The materials of construction for the CFW System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Carbon Steel with Internal Coating
- Copper Alloy with 15% Zinc or Less
- Elastomer
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The CFW System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Lubricating Oil
- Raw Water
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the CFW System require management:

- Cracking
- Hardening or Loss of Strength
- Long-Term Loss of Material
- Loss of Coating or Lining Integrity
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the CFW System components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)

- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.4.2.1.3 Main Condenser

Materials

The materials of construction for the CDR System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy Greater Than 15% Zinc
- Elastomer
- Glass
- Stainless Steel
- Stainless Steel Bolting

Environments

The CDR System components are exposed to the following environments:

- Air - Dry
- Air - Indoor Uncontrolled
- Condensation
- Raw Water
- Treated Water
- Treated Water >140°F

Due to steam quality, the environment of steam is identified as Treated Water >140°F.

Aging Effects Requiring Management

The following aging effects associated with the CDR System require management:

- Cracking
- Hardening and Loss of Strength
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the CDR System components:

- Bolting Integrity (B.2.3.10)
- Compressed Air Monitoring (B.2.3.14)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- One-Time Inspection (B.2.3.20)
- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

3.4.2.1.4 Main Steam

Materials

The materials of construction for the MST System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Stainless Steel

Environments

The MST System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Steam
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the MST System require management:

- Cracking
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the MST System components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.4.2.1.5 Off-Gas

Materials

The materials of construction for the Off-Gas System components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloy with 15% Zinc or Less Bolting
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Stainless Steel
- Stainless Steel Bolting

Environments

The Off-Gas System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Closed-Cycle Cooling Water
- Condensation
- Gas
- Soil
- Steam
- Treated Water
- Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the Off-Gas System require management:

- Cracking
- Long-term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the Off-Gas System components:

- Bolting Integrity (B.2.3.10)
- Buried and Underground Piping and Tanks (B.2.3.27)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)

3.4.2.1.6 Turbine Generator

Materials

The materials of construction for the TGS components are:

- Carbon and Low Alloy Steel Bolting
- Carbon Steel
- Copper Alloys with 15% Zinc or Less
- Copper Alloy Greater Than 15% Zinc
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Environments

The TGS components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Gas
- Lubricating Oil
- Raw Water
- Treated Water
- Treated Water >140°F

Due to steam quality, the environment of steam is identified as Treated Water >140°F

Aging Effects Requiring Management

The following aging effects associated with the TGS require management:

- Cracking
- Long-Term Loss of Material
- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following AMPs manage the aging effects for the TGS components:

- Bolting Integrity (B.2.3.10)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Flow-Accelerated Corrosion (B.2.3.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
- Lubricating Oil Analysis (B.2.3.25)
- One-Time Inspection (B.2.3.20)

- Selective Leaching (B.2.3.21)
- Water Chemistry (B.2.3.2)

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 SLRA. For the S&PC Systems, those programs are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.4.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in SRP-SLR Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses." For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

Cumulative fatigue damage of S&PC Systems components, as described in SRP-SLR Item 3.4.2.2.1, is addressed as a TLAA in Section 4.3, *Metal Fatigue*. Identification of components subject to this aging effect are addressed in Section 4.3 only and not in AMR Tables 3.4.2-X because all S&PC Systems components have been dispositioned as 10 CFR 54.21(c)(1)(i) and do not require aging management.

3.4.2.2.2 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor stainless steel (SS) piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific operating experience (OE) and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of

SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is occurring, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Ambient air at MNGP is not subject to a marine atmosphere. MNGP is located in the vicinity of a major road that is routinely salted for snow and ice. A review of the over 69,000 ARs created during the 01/01/2010 to 07/29/2021 period was performed to determine if the proximity to the salted road has resulted in any plant-specific OE for cracking of the susceptible materials to chlorides in an air environment. The results of this review show that the ambient air environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. As such, stainless steel components exposed to air or condensation in the S&PC Systems are not susceptible to cracking due to SCC.

Plant-specific OE associated with insulated stainless steel components in the S&PC Systems has been evaluated to determine if prolonged exposure to the outdoor air or condensation environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at MNGP for insulated stainless steel components for these environments 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.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that cracking is not occurring in stainless steel components exposed to air indoor uncontrolled and condensation, and, insulated stainless steel components exposed to outdoor air and condensation. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in B.2.3.20.

3.4.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain, and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion.

GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Ambient air at MNGP is not subject to a marine atmosphere. MNGP is located in the vicinity of a major road that is routinely salted for snow and ice. A review of the over 69,000 ARs created during the 01/01/2010 to 07/29/2021 period was performed to determine if the proximity to the salted road has resulted in any plant-specific OE for loss of material of the susceptible materials to chlorides in an air environment. The results of this review show that the ambient air environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. As such, stainless steel components exposed to air or condensation in the S&PC Systems are not susceptible to loss of material.

Plant-specific OE associated with insulated stainless steel components in the S&PC Systems has been evaluated to determine if prolonged exposure to the outdoor air or condensation environments has resulted in loss of material due to pitting or crevice corrosion. Loss of material due to pitting or crevice corrosion has not been identified as an aging effect at MNGP for insulated stainless steel components for these environments 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.

Consistent with the recommendation of GALL-SLR, the One-Time Inspection AMP will confirm that loss of material is not occurring in stainless steel components exposed to air and condensation, and, insulated stainless steel components exposed to outdoor air and condensation. Deficiencies will be documented in accordance with the site's 10 CFR Part 50, Appendix B, Section XVI, CAP. The One-Time Inspection AMP is described in B.2.3.20.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2, of this SRP-SLR).

QA provisions applicable to SLR are discussed in Section B.1.3.

3.4.2.2.5 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The OE process and acceptance criteria are described in 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 (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: (i) alternative examination methods (e.g., volumetric versus external visual); (ii) augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and (iii) additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be *implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.*

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

MNGP OE over the past 10 years shows no instances that meet the criteria of recurring internal corrosion for metals containing raw water, waste water, or treated water in the S&PC Systems; therefore, recurring internal corrosion is not an applicable aging effect at MNGP. There is no need to augment the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP due to recurring internal corrosion.

3.4.2.2.7 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.

<u>*Susceptible Material*</u>*: If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines whether the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is*

considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

<u>Aggressive Environment</u>: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of *plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.*

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. 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.

Not Applicable – There are no aluminum components within the S&PC Systems.

3.4.2.2.8 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) *plant-specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.*

Not Applicable – There are no components exposed to concrete susceptible to SCC in the S&PC Systems.

3.4.2.2.9 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate *that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and 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.

Not Applicable – There are no aluminum components within the S&PC Systems.

3.4.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the S&PC System components:

- Section 4.3, *Metal Fatigue*

3.4.3 Conclusion

S&PC Systems piping, fittings, and components that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4. The AMPs selected to manage aging effects for S&PC System components are identified in the summaries in Section 3.4.2 above.

A description of these AMPs is provided in Appendix B along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with S&PC System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the CLB during the SPEO.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
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, SRP-SLR Section 4.3, "Metal Fatigue"	Yes (SRP-SLR Section 3.4.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage is an aging effect assessed by a fatigue TLAA in Section 4.3. Identification of components subject to this aging effect are addressed in Section 4.3 only and not in AMR Tables 3.4.2-X because all S&PC Systems components have been dispositioned as 10 CFR 54.21(c)(1)(i) and do not require aging management. Further evaluation is documented in Section 3.4.2.2.1.
3.4.1-002	Stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Consistent with NUREG-2191. This line is also applied to heat exchanger components. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of stainless steel piping, piping components, and heat exchanger components exposed to air indoor uncontrolled or condensation. Further evaluation is documented in Section 3.4.2.2.2.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-003	Stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Consistent with NUREG-2191. This line is also applied to heat exchanger components. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of stainless steel piping, piping components, and heat exchanger components exposed to air indoor uncontrolled or condensation. Further evaluation is documented in Section 3.4.2.2.3.
3.4.1-004	Not applicable. This line item only applies to PWRs.				
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. The Flow-Accelerated Corrosion (B.2.3.9) AMP is used to manage wall thinning of steel piping and piping components exposed to steam or treated water. This line item is also applied to components in the Auxiliary Systems.
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. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of preload of metallic closure bolting in any environment.
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 closure bolting in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-009	Steel, stainless steel, nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of material of stainless steel and carbon steel closure bolting exposed to air indoor uncontrolled or air outdoor.
3.4.1-011	Stainless steel piping, piping components, tanks, heat exchanger components exposed to steam, treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP-XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage cracking of stainless steel piping, piping components, pump casings, and heat exchanger components exposed to steam or treated water >60°C (>140°F). This line item is also applied to components in the Auxiliary Systems.
3.4.1-012	Steel tanks exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel tanks exposed to treated water.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

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," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line is also applied to turbine casings and heat exchangers along with components in the Reactor Vessels, Internals, and RCS. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping, piping components, heat exchangers, and turbine casings exposed to reactor coolant, steam or treated water.
3.4.1-015	Steel heat exchanger components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel heat exchanger components exposed to treated water. This line item is also applied to components in the ESF, and Auxiliary Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
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," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line item is also applied to heat exchanger components. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy piping, piping components, and heat exchanger components exposed to treated water.
3.4.1-018	Copper alloy, stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. This line item is used for components in the ESF. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage reduction of heat transfer in copper alloy heat exchanger tubes exposed to treated water.
3.4.1-019	Stainless steel, steel heat exchanger components exposed to raw water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no stainless steel or steel heat exchanger components exposed to raw water within the scope of the Open-Cycle Cooling Water System (B.2.3.11) AMP in the S&PC Systems. Stainless steel and steel heat exchanger components exposed to raw water in the S&PC Systems are non GL 89-13 components managed by item 3.4.1-091.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-020	Copper alloy, stainless steel piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no copper alloy or stainless steel piping and piping components exposed to raw water in the S&PC Systems.
3.4.1-022	Stainless steel, copper alloy, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable. There are no copper alloy, stainless steel, or steel heat exchanger tubes exposed to raw water that have a heat transfer intended function in the S&PC Systems.
3.4.1-023	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the S&PC Systems.
3.4.1-025	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no steel heat exchanger components exposed to closed-cycle cooling water in the S&PC Systems.
3.4.1-026	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Consistent with NUREG-2191. This line item is applied to the ethylene glycol side of the H_2O_2 Sample Cooler. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of the stainless steel H_2O_2 Sample Cooler.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-027	Copper alloy piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no copper alloy piping or piping components exposed to closed-cycle cooling water in the S&PC Systems.
3.4.1-028	Steel, stainless steel, copper alloy heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no steel, stainless steel, or copper alloy heat exchanger components that have a heat transfer intended function exposed to closed-cycle cooling water in the S&PC Systems.
3.4.1-030	Steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material of steel tanks exposed to soil or concrete.
3.4.1-032	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not applicable. There are no gray cast iron or ductile iron piping, or piping components exposed to soil in the S&PC Systems.
3.4.1-033	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components exposed to treated water, raw water, closed-cycle cooling water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. This line is also applied to heat exchanger components. The Selective Leaching (B.2.3.21) AMP is used to manage loss of material of gray cast iron and copper alloy >15% Zn piping and piping components and heat exchanger components exposed to treated water and raw water. This line item is also applied to components in the Auxiliary Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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.2.3.23) AMP is used to manage the loss of material of steel surfaces exposed to air indoor uncontrolled.
3.4.1-035	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum piping or piping components in the S&PC Systems. Further evaluation is documented in Section 3.4.2.2.9.
3.4.1-036	Steel piping, piping components exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no steel piping or piping components exposed to outdoor air internally in the S&PC Systems.
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.2.3.24) AMP is used to manage loss of material of steel piping and piping components exposed to condensation.
3.4.1-038	Not applicable. This line item only applies to PWRs.				

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-040	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. This line item is also applied to heat exchanger components. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of steel piping, piping components, and heat exchanger components exposed to lubricating oil.
3.4.1-041	Not applicable. This line item only applies to PWRs.				
3.4.1-042	Not applicable. This line item only applies to PWRs.				
3.4.1-043	Copper alloy piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. This line item is also applied to heat exchanger components. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of copper alloy piping and piping components, and heat exchanger components exposed to lubricating oil.
3.4.1-044	Stainless steel piping, piping components, heat exchanger components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis (B.2.3.25) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping, piping components, and heat exchanger components exposed to lubricating oil.
3.4.1-045	Aluminum heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no aluminum heat exchanger tubes in the S&PC Systems.
3.4.1-046	Not applicable. This line item only applies to PWRs.				

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-047	Stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage loss of material of stainless steel piping and piping components exposed to soil.
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 components exposed to soil or concrete in the S&PC Systems.
3.4.1-050	Steel piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks (B.2.3.27) AMP is used to manage loss of material of steel piping and piping components exposed to soil.
3.4.1-051	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. There are no steel piping or piping components exposed to concrete in the S&PC Systems. Further evaluation is documented in Section 3.4.2.2.8.
3.4.1-052	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. There are no aluminum piping or piping components exposed to gas in the S&PC Systems.
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 or piping components exposed to air with borated water leakage in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
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. Copper alloy components exposed to gas and copper alloy <15% Zn components, including bolting, exposed to air indoor uncontrolled do not have any aging effects that require management.
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. Glass piping components exposed to air indoor uncontrolled, treated water, or lubricating oil do not have any aging effects that require management.
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 or piping components exposed to air with borated water leakage in the S&PC Systems.
3.4.1-057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not applicable. There are no PVC components in the S&PC Systems.
3.4.1-058	Stainless steel piping, piping components exposed to gas	None	None	No	Not applicable. There are no stainless steel piping, piping components exposed to gas in the S&PC Systems.
3.4.1-059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. This item is also applied to heat exchanger components. Steel piping and heat exchanger components exposed to gas do not have any aging effects that require management

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-060	Metallic piping, piping components exposed to steam, treated water	Wall thinning due to erosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. This line item is also applied to heat exchanger and turbine hood component types. The Flow-Accelerated Corrosion (B.2.3.9) AMP is used to manage wall thinning of metallic piping, piping components, turbine hoods and heat exchanger components exposed to steam and treated water.
3.4.1-061	Metallic piping, piping components, tanks exposed to raw water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes (SRP-SLR Section 3.4.2.2.6)	Not applicable. Based on a review of MNGP OE, there are no instances of recurring internal corrosion in the S&PC Systems.
3.4.1-062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material of steel tanks exposed to treated water.
3.4.1-063	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP is used to manage loss of material of insulated steel tanks exposed to air outdoor.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

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	Not used. Aging effects for non-metallic thermal insulation are addressed by item 3.2.1-087.
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. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) AMP is used to manage loss of coating or lining integrity of internally coated steel components exposed to raw or treated water.
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is used to manage loss of material in the base metal of internally coated components in the S&PC Systems.
3.4.1-068	Gray cast iron, ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, waste water	Loss of material due to selective leaching	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Not applicable. There are no gray cast iron or ductile iron piping or piping components with internal coatings in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-070	Stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, waste water	Loss of material due to general (steel; copper alloy in raw water, waste water only), pitting, crevice corrosion, MIC (raw water, waste water environments only)	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage loss of material of steel closure bolting exposed to lubricating oil or treated water.
3.4.1-072	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/ bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground piping and Tanks AMP is used to manage cracking in carbon steel and stainless steel piping and piping components exposed to soil.
3.4.1-073	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity (B.2.3.10) AMP is used to manage cracking of stainless steel bolting exposed to air indoor uncontrolled and air outdoor.
3.4.1-074	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks (B.2.3.27)," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no stainless steel underground components in the S&PC Systems.
3.4.1-075	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable. There are no heat exchanger tubes exposed to air or condensation in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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.2.3.23) AMP is used to manage hardening or loss of strength of elastomer expansion joints.
3.4.1-078	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer components exposed to air or condensation internally in the S&PC Systems.
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. The One-Time Inspection (B.2.3.20) AMP is used to manage long-term loss of material of steel components exposed to raw or treated water.
3.4.1-082	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. There are no stainless steel piping or piping components exposed to concrete in the S&PC Systems. Further evaluation is documented in Section 3.4.2.2.8.
3.4.1-083	Stainless steel, nickel alloy tanks exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel tanks exposed to treated water.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-084	Stainless steel, nickel alloy piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping and piping components exposed to steam.
3.4.1-085	Stainless steel, nickel alloy piping, piping components, PWR heat exchanger components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191 with exception for the Water Chemistry (B.2.3.2) AMP. The Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20) AMPs are used to manage loss of material of stainless steel piping, piping components, and heat exchanger components exposed to treated water.
3.4.1-086	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes internal to components exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no heat exchanger tubes exposed to air or condensation internally in the S&PC Systems.
3.4.1-089	Steel, stainless steel, copper alloy piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no piping and piping components exposed to raw water in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-090	Steel, stainless steel, copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage reduction of heat transfer of copper alloy heat exchanger tubes exposed to raw water.
3.4.1-091	Steel, stainless steel, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP is used to manage loss of material of steel, stainless steel, and copper alloy heat exchanger components exposed to raw water. This line item is also applied to components in the Auxiliary Systems.
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 or piping components exposed to soil in the S&PC Systems.
3.4.1-094	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum underground piping or piping components in the S&PC Systems. Further evaluation is documents in Section 3.4.2.2.9.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-095	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Not applicable. There are no stainless steel or nickel alloy underground piping or piping components in the S&PC Systems. Further evaluation is documents in Section 3.4.2.2.3.
3.4.1-096	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no aluminum tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP.
3.4.1-097	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP. Further evaluation is documents in Section 3.4.2.2.9.
3.4.1-098	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Not applicable. There are no stainless steel or nickel alloy tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP. Further evaluation is documents in Section 3.4.2.2.3.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-099	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no stainless steel tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP.
3.4.1-100	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Not applicable. There are no stainless steel tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP. Further evaluation is documents in Section 3.4.2.2.2.
3.4.1-101	Stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Not applicable. There are no stainless steel tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP.
3.4.1-102	Aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum tanks within the scope of the Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP. Further evaluation is documented in Section 3.4.2.2.7.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems

Item Number	Component	Aging Effect / Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-103	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.3)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage loss of material of insulated stainless steel piping and piping components exposed to air outdoor or condensation. Further evaluation is documented in Section 3.4.2.2.3.
3.4.1-104	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.2)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP is used to manage cracking of insulated stainless steel piping and piping components exposed to air outdoor or condensation. Further evaluation is documented in Section 3.4.2.2.2.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-105	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no insulated aluminum components in the S&PC Systems. Further evaluation is documented in Section 3.4.2.2.7.
3.4.1-106	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. This item is also applied to heat exchanger components. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage cracking of copper alloy >15% Zn piping, piping components, and heat exchanger components exposed to condensation, air indoor uncontrolled, or air outdoor. This line item is also applied to components in the Reactor Vessel, Internals, and Reactor Coolant, ESF, and Auxiliary Systems.
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 tanks in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-109	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, waste water	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum piping or piping components in the S&PC Systems. Further evaluation is documented in Section 3.4.2.2.7.
3.4.1-112	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.7)	Not applicable. There are no aluminum underground piping or piping components in the S&PC Systems.
3.4.1-114	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Not applicable. There are no titanium components in the S&PC Systems.
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 components in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-116	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, "Closed Treated Water Systems"	No	Not applicable. There are no titanium components in the S&PC Systems.
3.4.1-117	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no aluminum components exposed to soil or concrete in the S&PC Systems.
3.4.1-119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no insulated aluminum components in the S&PC Systems. Further evaluation is documented in Section 3.4.2.2.9.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-120	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," or AMP XI.M42, "Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. There are no aluminum components exposed to raw water in the S&PC Systems. Further evaluation is documented in Section 3.4.2.2.9.
3.4.1-122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is used to manage loss of material of elastomer expansion joints exposed to air indoor uncontrolled.
3.4.1-123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no elastomer components exposed to air internally in the S&PC Systems.
3.4.1-124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. There are no PVC components in the S&PC Systems.

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-125	PVC piping, piping components, tanks exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. There are no PVC components in the S&PC Systems.
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 components in the S&PC Systems.
3.4.1-127	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. There are no aluminum components exposed to air with borated water leakage in the S&PC Systems.
3.4.1-128	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. There are no copper components exposed to concrete in the Power and Steam Conversion Systems.
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 components exposed to soil or underground in the S&PC Systems.
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 components in the S&PC Systems.
3.4.1-131	Not applicable. This line item only applies to PWRs.				
3.4.1-132	Not applicable. This line item only applies to PWRs.				

Table 3.4-1: Summary of the Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-133	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no aluminum components exposed to raw water in the S&PC Systems.
3.4.1-134	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no titanium components in the S&PC Systems.
3.4.1-135	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable. There are no polymeric components in the S&PC Systems.

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VIII.H.S-421	3.4.1-073	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Cracking	Bolting Integrity (B.2.3.10)	VIII.H.S-421	3.4.1-073	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Outdoor (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Expansion Joints	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-428	3.4.1-077	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Expansion Joints	Pressure Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-471	3.4.1-122	A
Expansion Joints	Pressure Boundary	Elastomer	Treated Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-75	3.3.1-085	A
Expansion Joints	Pressure Boundary	Elastomer	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-76	3.3.1-096	A
Insulated Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.H.S-452b	3.4.1-104	A
Insulated Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.H.S-451b	3.4.1-103	A
Insulated Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.H.S-452b	3.4.1-104	A
Insulated Piping, Piping Components	Pressure Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.H.S-451b	3.4.1-103	A
Insulated Tanks (Condensate Storage Tank)	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.H.S-402b	3.4.1-063	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Insulated Tanks (Condensate Storage Tank)	Pressure Boundary	Carbon Steel	Concrete (External)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.E.SP-115	3.4.1-030	A
Insulated Tanks (Condensate Storage Tank)	Pressure Boundary	Carbon Steel	Soil (External)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.E.SP-115	3.4.1-030	A
Insulated Tanks (Condensate Storage Tank)	Pressure Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Insulated Tanks (Condensate Storage Tank)	Pressure Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VIII.E.S-401	3.4.1-066	A
Insulated Tanks (Condensate Storage Tank)	Pressure Boundary	Carbon Steel (with Internal Coating)	Treated Water (Internal)	Loss of Material	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)	VIII.E.S-405	3.4.1-062	A
Insulated Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.H.S-452b	3.4.1-104	A
Insulated Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.H.S-451b	3.4.1-103	A
Insulated Valve Body	Pressure Boundary	Stainless Steel	Condensation (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.H.S-452b	3.4.1-104	A
Insulated Valve Body	Pressure Boundary	Stainless Steel	Condensation (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.H.S-451b	3.4.1-103	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping Elements	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-33	3.4.1-055	A
Piping Elements	Pressure Boundary	Glass	Treated Water (Internal)	None	None	VIII.I.SP-35	3.4.1-055	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Piping, Piping Components	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Soil (External) [Pipe segment C11-20-HK]	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.S-420	3.4.1-072	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Soil (External) [Pipe segment C11-20-HK]	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.SP-145	3.4.1-047	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B
Pump Casing (Condensate Service Jockey Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Condensate Service Jockey Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Pump Casing (Condensate Service Jockey Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Pump Casing (Condensate Service Jockey Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Pump Casing (Condensate Service Pump)	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Condensate Service Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Pump Casing (Condensate Service Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Pump Casing (Condensate Service Pump)	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Pump Casing (High Pressure Decontamination Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (High Pressure Decontamination Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Pump Casing (High Pressure Decontamination Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Pump Casing (High Pressure Decontamination Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Valve Body	Pressure Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Pressure Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Pressure Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Valve Body	Pressure Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Valve Body	Pressure Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.E.SP-27	3.4.1-033	A
Valve Body	Pressure Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Valve Body	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Valve Body	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A

Table 3.4.2-1: Condensate Storage – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Pressure Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VIII.H.S-421	3.4.1-073	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-428	3.4.1-077	A
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-471	3.4.1-122	A
Expansion Joints	Leakage Boundary	Elastomer	Treated Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.A4.AP-101	3.3.1-085	A
Expansion Joints	Leakage Boundary	Elastomer	Treated Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.G.AP-76	3.3.1-096	A

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Condensate Pump Motor Upper and Lower Bearing Cooler) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-92	3.4.1-043	A
Heat Exchanger - (Condensate Pump Motor Upper and Lower Bearing Cooler) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-92	3.4.1-043	A
Heat Exchanger - (Condensate Pump Motor Upper and Lower Bearing Cooler) Tubes	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger - (FW Heater Drain Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (FW Heater Drain Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (FW Heater Drain Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Heat Exchanger - (FW Heater Drain Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Heat Exchanger - (FW Heater Drain Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (FW Heater Drain Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (FW Heater Drain Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Heat Exchanger - (FW Heater Drain Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Heat Exchanger - (FW Heater) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (FW Heater) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (FW Heater) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Heat Exchanger - (FW Heater) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Heat Exchanger - (FW Heater) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4.1-005	C
Heat Exchanger - (FW Heater) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	C
Heat Exchanger - (FW Heater) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (FW Heater) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (FW Heater) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Heat Exchanger - (FW Heater) Tube Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Heat Exchanger - (RFP Lubricating Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (RFP Lubricating Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Heat Exchanger - (RFP Lubricating Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Heat Exchanger - (RFP Lubricating Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (RFP Lubricating Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (RFP Lubricating Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Coating or Lining Integrity	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28)	VIII.E.S-401	3.4.1-066	A
Heat Exchanger - (RFP Lubricating Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel (with Internal Coating)	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-414	3.4.1-067	E, 1
Heat Exchanger - (RFP Motor Cooler) Tube Side Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	C
Heat Exchanger - (RFP Motor Cooler) Tube Side Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Hoses	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Hoses	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-95	3.4.1-044	A
Hoses	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-95	3.4.1-044	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4.1-005	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4.1-005	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B
Pump Casing (Body Feed Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Body Feed Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casing (Body Feed Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Body Feed Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Pump Casing (Body Feed Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casing (Condensate Demineralizer Holding Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Condensate Demineralizer Holding Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casing (Condensate Demineralizer Holding Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casing (Condensate Demineralizer Holding Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Pump Casing (Condensate Demineralizer Holding Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casing (Condensate Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Condensate Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casing (Condensate Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Condensate Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Pump Casing (Condensate Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casing (Main Lubricating Oil Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Main Lubricating Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Main Lubricating Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Precoat Injection Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Precoat Injection Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casing (Precoat Injection Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casing (Precoat Injection Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Pump Casing (Precoat Injection Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casing (Precoat Recycle Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Precoat Recycle Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casing (Precoat Recycle Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Precoat Recycle Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Pump Casing (Precoat Recycle Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casing (Reactor Feed Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Reactor Feed Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Reactor Feed Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (RFP Seal Drain Tank Pump)	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (RFP Seal Drain Tank Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casing (RFP Seal Drain Tank Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casing (RFP Seal Drain Tank Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Pump Casing (RFP Seal Drain Tank Pump)	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Tanks (Auxiliary Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.D2.SP-118 a	3.4.1-002	A
Tanks (Auxiliary Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	C

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (Auxiliary Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-162	3.4.1-083	A
Tanks (Auxiliary Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-162	3.4.1-083	B
Tanks (Body Feed Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Body Feed Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Tanks (Body Feed Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A
Tanks (Body Feed Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Tanks (Condensate Demineralizer Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Condensate Demineralizer Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Tanks (Condensate Demineralizer Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A
Tanks (Condensate Demineralizer Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Tanks (Dissolution Column)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Dissolution Column)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Dissolution Column)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A
Tanks (Dissolution Column)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Tanks (Precoat Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.D2.SP-118 a	3.4.1-002	A
Tanks (Precoat Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	C
Tanks (Precoat Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-162	3.4.1-083	A
Tanks (Precoat Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-162	3.4.1-083	B
Tanks (RFP Seal Drain Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.D2.SP-118 a	3.4.1-002	A
Tanks (RFP Seal Drain Tank)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	C
Tanks (RFP Seal Drain Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-162	3.4.1-083	A
Tanks (RFP Seal Drain Tank)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-162	3.4.1-083	B
Tanks (RFP Seal Drain Tank)	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-97	3.4.1-011	A
Tanks (RFP Seal Drain Tank)	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-97	3.4.1-011	B
Tanks (RFP Lubricating Oil Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (RFP Lubricating Oil Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (RFP Lubricating Oil Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4.1-005	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B

Table 3.4.2-2: Condensate and Feedwater – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-16	3.4.1-005	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.3.28) program to manage loss of material of the base metal due to general, pitting and crevice corrosion and MIC in the internally coated carbon steel condensate and feedwater piping with an internal environment of raw water.

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Treated Water (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-418	3.4.1-070	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Treated Water (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VIII.H.S-421	3.4.1-073	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Expansion Joints	Holdup and Plateout	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-428	3.4.1-077	A
Expansion Joints	Holdup and Plateout	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-471	3.4.1-122	A
Expansion Joints	Holdup and Plateout	Elastomer	Treated Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.A4.AP-101	3.3.1-085	A
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Hardening or Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-428	3.4.1-077	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Expansion Joints	Leakage Boundary	Elastomer	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-471	3.4.1-122	A
Expansion Joints	Leakage Boundary	Elastomer	Treated Water (Internal)	Hardening or Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.A4.AP-101	3.3.1-085	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Tube Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Tube Side Components	Holdup and Plateout	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Tube Side Components	Holdup and Plateout	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (Condenser Mech Vac Pump Seal Water Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger - (Main Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Main Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (Main Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Heat Exchanger - (Main Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Heat Exchanger - (Main Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	C
Heat Exchanger - (Main Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Main Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger - (Main Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Heat Exchanger - (Main Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Main Condenser) Shell Side Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	C
Heat Exchanger - (Main Condenser) Tubes	Holdup and Plateout	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger - (Main Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Main Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water (External)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Main Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140°F (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	C
Heat Exchanger - (Main Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140°F (External)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	D
Heat Exchanger - (Main Condenser) Tubesheet	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Raw Water (External)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.C1.A-473b	3.3.1-160	E, 1
Heat Exchanger - (Main Condenser) Tubesheet	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Raw Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger - (Main Condenser) Tubesheet	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Raw Water (External)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-30	3.4.1-033	C

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Main Condenser) Tubesheet	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-101	3.4.1-016	C
Heat Exchanger - (Main Condenser) Tubesheet	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.E.SP-55	3.4.1-033	C
Heat Exchanger - (Main Condenser) Tubesheet	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.A.SP-101	3.4.1-016	D
LP Turbine Hood	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
LP Turbine Hood	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
LP Turbine Hood	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
LP Turbine Hood	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
LP Turbine Hood	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	C
LP Turbine Hood	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
LP Turbine Hood	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
LP Turbine Hood	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
LP Turbine Hood	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
LP Turbine Hood	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	C

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping Elements	Holdup and Plateout	Glass	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-33	3.4.1-055	A
Piping Elements	Holdup and Plateout	Glass	Treated Water (Internal)	None	None	VIII.I.SP-35	3.4.1-055	A
Piping Elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-33	3.4.1-055	A
Piping Elements	Leakage Boundary	Glass	Treated Water (Internal)	None	None	VIII.I.SP-35	3.4.1-055	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Pump Casings (Condenser Mechanical Vacuum Pump)	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casings (Condenser Mechanical Vacuum Pump)	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	C
Pump Casings (Condenser Mechanical Vacuum Pump)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casings (Condenser Mechanical Vacuum Pump)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casings (Condenser Mechanical Vacuum Pump)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casings (Condenser Mechanical Vacuum Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casings (Condenser Mechanical Vacuum Pump)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	C

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casings (Condenser Mechanical Vacuum Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casings (Condenser Mechanical Vacuum Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casings (Condenser Mechanical Vacuum Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casings (MVP Recirculation Seal Pump)	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casings (MVP Recirculation Seal Pump)	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	C
Pump Casings (MVP Recirculation Seal Pump)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casings (MVP Recirculation Seal Pump)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casings (MVP Recirculation Seal Pump)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casings (MVP Recirculation Seal Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casings (MVP Recirculation Seal Pump)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	C
Pump Casings (MVP Recirculation Seal Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casings (MVP Recirculation Seal Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casings (MVP Recirculation Seal Pump)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Tanks (MVP Moisture Separator Tank)	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (MVP Moisture Separator Tank)	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-26	3.3.1-055	A
Tanks (MVP Moisture Separator Tank)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Tanks (MVP Moisture Separator Tank)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (MVP Moisture Separator Tank)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Tanks (MVP Moisture Separator Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (MVP Moisture Separator Tank)	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VII.E5.A-26	3.3.1-055	A
Tanks (MVP Moisture Separator Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Tanks (MVP Moisture Separator Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A
Tanks (MVP Moisture Separator Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Leakage Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A

Table 3.4.2-3: Main Condenser – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Pressure Boundary	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Dry (Internal)	Loss of Material	Compressed Air Monitoring (B.2.3.14)	VII.D.A-764	3.3.1-235	A
Valve Body	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) program is being substituted for the Open-Cycle Cooling Water System (B.2.3.11) program to manage cracking in copper alloy with greater than 15% zinc piping with an environment of raw water.

Table 3.4.2-4: Main Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Orifice	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.B2.SP-118a	3.4.1-002	A
Orifice	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-127a	3.4.1-003	A
Orifice	Holdup and Plateout	Stainless Steel	Steam (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4.1-011	A
Orifice	Holdup and Plateout	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.B2.SP-98	3.4.1-011	B
Orifice	Holdup and Plateout	Stainless Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4.1-084	A
Orifice	Holdup and Plateout	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-155	3.4.1-084	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4.1-014	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-160	3.4.1-014	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-15	3.4.1-005	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Wall thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4.1-060	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.B2.SP-118a	3.4.1-002	A

Table 3.4.2-4: Main Steam – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-127a	3.4.1-003	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Steam (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4.1-011	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.B2.SP-98	3.4.1-011	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4.1-084	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-155	3.4.1-084	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Steam (Internal)	Wall thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4.1-060	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Strainer (Element)	Filter	Stainless Steel	Steam (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4.1-011	A
Strainer (Element)	Filter	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.B2.SP-98	3.4.1-011	B
Strainer (Element)	Filter	Stainless Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4.1-084	A
Strainer (Element)	Filter	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-155	3.4.1-084	B
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4.1-014	A

Table 3.4.2-4: Main Steam – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-160	3.4.1-014	B
Valve Body	Holdup and Plateout	Stainless Steel	Steam (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.B2.SP-98	3.4.1-011	A
Valve Body	Holdup and Plateout	Stainless Steel	Steam (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.B2.SP-98	3.4.1-011	B
Valve Body	Holdup and Plateout	Stainless Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-155	3.4.1-084	A
Valve Body	Holdup and Plateout	Stainless Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-155	3.4.1-084	B
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.B2.SP-118a	3.4.1-002	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-127a	3.4.1-003	A
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1- 009	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1- 006	A
Bolting (Closure)	Mechanical Closure	Copper Alloy with 15% Zinc or Less Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1- 006	A
Bolting (Closure)	Mechanical Closure	Copper Alloy with 15% Zinc or Less Bolting	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-6	3.4.1-054	C
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VIII.H.S-421	3.4.1- 073	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1- 009	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1- 006	A
Heat Exchanger - (Condenser) Shell Side Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	C
Heat Exchanger - (Condenser) Shell Side Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	C
Heat Exchanger - (Condenser) Shell Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Condenser) Shell Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Condenser) Shell Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Condenser) Shell Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Drain Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Drain Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Heat Exchanger - (Drain Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Drain Cooler) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (Drain Cooler) Tube Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Drain Cooler) Tube Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Heat Exchanger - (Drain Cooler) Tube Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (Drain Cooler) Tube Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (H_2O_2 Sample Coolers) Tubes	Holdup and Plateout	Stainless Steel	Closed Cycle Cooling Water (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-25	3.4.1-026	E, 2
Heat Exchanger - (H_2O_2 Sample Coolers) Tubes	Holdup and Plateout	Stainless Steel	Condensation (Internal)	None	None	VIII.E.SP-127a	3.4.1-003	I, 1
Heat Exchanger - (H_2O_2 Sample Coolers) Tubes	Holdup and Plateout	Stainless Steel	Condensation (Internal)	None	None	VIII.E.SP-118a	3.4.1-002	I, 1

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Inter-Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Inter-Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Heat Exchanger - (Inter-Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (Inter-Condenser) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (Inter-Condenser) Tube sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Inter-Condenser) Tube sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Inter-Condenser) Tube sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Inter-Condenser) Tube sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Inter-Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger – (Inter-Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger - (Inter-Condenser) Tube Sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Inter-Condenser) Tube sheet	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger – (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (External)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger - (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Inter-Condenser) Tubes	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger - (Pre-Heater) Shell Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger - (Pre-Heater) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Heat Exchanger - (Pre-Heater) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-77	3.4.1-015	A
Heat Exchanger - (Pre-Heater) Shell Side Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-77	3.4.1-015	B
Heat Exchanger - (Pre-Heater) Tube Side Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	C
Heat Exchanger - (Pre-Heater) Tube Side Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	C
Heat Exchanger - (Pre-Heater) Tube Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Heat Exchanger - (Pre-Heater) Tube Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Heat Exchanger - (Pre-Heater) Tube Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger - (Pre-Heater) Tube Side Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Gas (Internal)	None	None	VIII.I.SP-4	3.4.1-059	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.SP-161	3.4.1-050	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4.1-014	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-160	3.4.1-014	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-15	3.4.1-005	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Steam (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.B2.S-408	3.4.1-060	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.E.S-16	3.4.1-005	A

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Holdup and Plateout	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-6	3.4.1-054	A
Piping, Piping Components	Holdup and Plateout	Copper Alloy with 15% Zinc or Less	Gas (Internal)	None	None	VIII.I.SP-6	3.4.1-054	A
Piping, Piping Components	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VIII.I.SP-6	3.4.1-054	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Condensation (Internal)	None	None	VIII.E.SP-127a	3.4.1-003	I, 1
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Condensation (Internal)	None	None	VIII.E.SP-118a	3.4.1-002	I, 1
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Soil (External)	Cracking	Buried and Underground Piping and Tanks (B.2.3.27)	VIII.H.S-420	3.4.1-072	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.E.S-16	3.4.1-005	A

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (Condensate Flash Tank)	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Condensate Flash Tank)	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	C
Tanks (Condensate Flash Tank)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Tanks (Condensate Flash Tank)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	C
Tanks (Condensate Flash Tank)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	D
Tanks (Recombiner)	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Tanks (Recombiner)	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	C
Tanks (Recombiner)	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	C
Tanks (Recombiner)	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	D
Tanks (Recombiner)	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	C

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tanks (Recombiner)	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	D
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Holdup and Plateout	Carbon Steel	Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.SP-60	3.4.1-037	A
Valve Body	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-160	3.4.1-014	A
Valve Body	Holdup and Plateout	Carbon Steel	Steam (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-160	3.4.1-014	B
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B
Valve Body	Holdup and Plateout	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-6	3.4.1-054	A
Valve Body	Holdup and Plateout	Copper Alloy with 15% Zinc or Less	Gas (Internal)	None	None	VIII.I.SP-6	3.4.1-054	A

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Holdup and Plateout	Copper Alloy with Greater Than 15% Zinc	Gas (Internal)	None	None	VIII.I.SP-6	3.4.1-054	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-118a	3.4.1-002	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-127a	3.4.1-003	A
Valve Body	Holdup and Plateout	Stainless Steel	Condensation (Internal)	None	None	VIII.E.SP-118a	3.4.1-002	I, 1
Valve Body	Holdup and Plateout	Stainless Steel	Condensation (Internal)	None	None	VIII.E.SP-127a	3.4.1-003	I, 1
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.E.SP-88	3.4.1-011	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.E.SP-88	3.4.1-011	B
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-87	3.4.1-085	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-87	3.4.1-085	B

Table 3.4.2-5: Off-Gas – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.S-432	3.4.1-081	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-73	3.4.1-014	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-73	3.4.1-014	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

Plant-Specific Notes

1. The condensation environment represents off-gas that does not have the potential to contain halides. Therefore, cracking and loss of material are not applicable aging effects.

2. Component is a tube-in-tube cooling coil. The sample stream (condensation) flows through the inner tube and the water/glycol mixture (Closed-Cycle Cooling Water) flows in the outer tube. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) is being substituted for the Closed Treated Water Systems (B.2.3.12) program to manage the loss of material in the inner stainless steel heat exchanger tube exposed to an external environment of CCCW.

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Lubricating Oil (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-418	3.4.1-070	A
Bolting (Closure)	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Lubricating Oil (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Cracking	Bolting Integrity (B.2.3.10)	VIII.H.S-421	3.4.1-073	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.3.10)	VIII.H.S-02	3.4.1-009	A
Bolting (Closure)	Mechanical Closure	Stainless Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity (B.2.3.10)	VIII.H.SP-142	3.4.1-006	A
Heat Exchanger (Exciter Air Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger (Exciter Air Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-29	3.2.1-044	C
Heat Exchanger (Exciter Air Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger (Exciter Air Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger (Exciter Air Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger (Generator Hydrogen Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger (Generator Hydrogen Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Gas (Internal)	None	None	VIII.I.SP-4	3.4.1-059	C
Heat Exchanger (Generator Hydrogen Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger (Generator Hydrogen Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger (Generator Hydrogen Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger (Isophase Bus Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger (Isophase Bus Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	V.D2.E-29	3.2.1-044	C
Heat Exchanger (Isophase Bus Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger (Isophase Bus Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger (Isophase Bus Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger (Stator Water Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	C
Heat Exchanger (Stator Water Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	C
Heat Exchanger (Stator Water Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger (Stator Water Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger (Stator Water Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	C
Heat Exchanger (Stator Water Cooling Heat Exchanger) Shell Side Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	D
Heat Exchanger (Stator Water Cooling Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	C
Heat Exchanger (Stator Water Cooling Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	C
Heat Exchanger (Stator Water Cooling Heat Exchanger) Tube Side Components	Leakage Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger (Steam Packing Exhauster) Shell Side Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	C

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat Exchanger (Steam Packing Exhauster) Shell Side Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	C
Heat Exchanger (Steam Packing Exhauster) Shell Side Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-80	3.4.1-085	A
Heat Exchanger (Steam Packing Exhauster) Shell Side Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-80	3.4.1-085	B
Heat Exchanger (Steam Packing Exhauster) Tube Side Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger (Steam Packing Exhauster) Tube Side Components	Holdup and Plateout	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Heat Exchanger (Turbine Lubricating Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger (Turbine Lubricating Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Heat Exchanger (Turbine Lubricating Oil Cooler) Shell Side Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat Exchanger (Turbine Lubricating Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Heat Exchanger (Turbine Lubricating e Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Heat Exchanger (Turbine Lubricating Oil Cooler) Tube Side Components	Leakage Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)	VIII.E.S-438	3.4.1-091	A
Piping Elements	Leakage Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-33	3.4.1-055	A
Piping Elements	Leakage Boundary	Glass	Lubricating Oil (Internal)	None	None	VIII.I.SP-10	3.4.1-055	A
Piping Elements	Leakage Boundary	Glass	Treated Water (Internal)	None	None	VIII.I.SP-35	3.4.1-055	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Piping, Piping Components	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Piping, Piping Components	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Piping, Piping Components	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-6	3.4.1-054	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-92	3.4.1-043	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-92	3.4.1-043	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-101	3.4.1-016	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with 15% Zinc or Less	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.A.SP-101	3.4.1-016	B
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-92	3.4.1-043	A
Piping, Piping Components	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-92	3.4.1-043	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Piping, Piping Components	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-95	3.4.1-044	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-95	3.4.1-044	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Piping, Piping Components	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B
Pump Casing (Emergency Bearing Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Emergency Bearing Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Emergency Bearing Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Emergency Bearing Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Emergency H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Emergency H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Emergency H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (EPR Oil Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (EPR Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (EPR Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Main H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Main H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Main H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Recirc H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Recirc H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Recirc H2 Seal Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Seal Oil Vacuum Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Seal Oil Vacuum Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Seal Oil Vacuum Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Stator Liquid Cooling Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Pump Casing (Stator Liquid Cooling Pump)	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	C
Pump Casing (Stator Liquid Cooling Pump)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	C
Pump Casing (Stator Liquid Cooling Pump)	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	D
Pump Casing (Stator Liquid Cooling Pump)	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	C
Pump Casing (Stator Liquid Cooling Pump)	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	D
Pump Casing (Steam Packing Exhauster Blower)	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Steam Packing Exhauster Blower)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Pump Casing (Steam Packing Exhauster Blower)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Pump Casing (Steam Packing Exhauster Blower)	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Pump Casing (Turb Aux Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump Casing (Turb Aux Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turb Aux Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turb Aux Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turb Lubricating Oil Purifier Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Turb Lubricating Oil Purifier Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turb Lubricating Oil Purifier Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turbine Bearing Lift Pump)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Pump Casing (Turbine Bearing Lift Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turbine Bearing Lift Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turning Gear Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turning Gear Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Pump Casing (Turning Gear Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Pump Casing (Turning Gear Oil Pump)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (Clean Lubricating Oil Storage Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Clean Lubricating Oil Storage Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Tanks (Clean Lubricating Oil Storage Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (Dirty Lubricating Oil Storage Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Dirty Lubricating Oil Storage Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Tanks (Dirty Lubricating Oil Storage Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (LO Purifier Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (LO Purifier Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Tanks (LO Purifier Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (Lubricating Oil Dump Overflow Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Lubricating Oil Dump Overflow Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (Lubricating Oil Dump Overflow Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (Lubricating Oil Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Lubricating Oil Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Tanks (Lubricating Oil Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (Moisture Separator Drain Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Moisture Separator Drain Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Tanks (Moisture Separator Drain Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A
Tanks (Moisture Separator Drain Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Tanks (Moisture Separator)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Moisture Separator)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Tanks (Moisture Separator)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A
Tanks (Moisture Separator)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Tanks (Oily Water Separator Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tanks (Oily Water Separator Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Tanks (Oily Water Separator Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (Seal Oil Detraining Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Seal Oil Detraining Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Tanks (Seal Oil Detraining Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Tanks (Stator Cooling Surge Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Stator Cooling Surge Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Tanks (Stator Cooling Surge Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.E.SP-75	3.4.1-012	A
Tanks (Stator Cooling Surge Tank)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.E.SP-75	3.4.1-012	B
Tanks (Turbine Lubricating Oil Purifier Drain Tank)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Tanks (Turbine Lubricating Oil Purifier Drain Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	C
Tanks (Turbine Lubricating Oil Purifier Drain Tank)	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	C
Turbine Casings (H.P. Turbine)	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Turbine Casings (H.P. Turbine)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Turbine Casings (H.P. Turbine)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	C
Turbine Casings (H.P. Turbine)	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	D
Valve Body	Holdup and Plateout	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Valve Body	Holdup and Plateout	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Valve Body	Holdup and Plateout	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A
Valve Body	Holdup and Plateout	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-91	3.4.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-91	3.4.1-040	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Valve Body	Leakage Boundary	Carbon Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B.2.3.9)	VIII.D2.S-408	3.4.1-060	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-454	3.4.1-106	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-92	3.4.1-043	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-92	3.4.1-043	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-101	3.4.1-016	A
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.E.SP-55	3.4.1-033	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.A.SP-101	3.4.1-016	B
Valve Body	Leakage Boundary	Gray Cast Iron	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	VIII.H.S-29	3.4.1-034	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Long-Term Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.S-432	3.4.1-081	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.B2.SP-73	3.4.1-014	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Selective Leaching (B.2.3.21)	VIII.A.SP-27	3.4.1-033	A
Valve Body	Leakage Boundary	Gray Cast Iron	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.B2.SP-73	3.4.1-014	B
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking	One-Time Inspection (B.2.3.20)	VIII.A.SP-118a	3.4.1-002	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-127a	3.4.1-003	A
Valve Body	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.3.25)	VIII.A.SP-95	3.4.1-044	A
Valve Body	Leakage Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.A.SP-95	3.4.1-044	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.3.20)	VIII.C.SP-87	3.4.1-085	A
Valve Body	Leakage Boundary	Stainless Steel	Treated Water (Internal)	Loss of Material	Water Chemistry (B.2.3.2)	VIII.C.SP-87	3.4.1-085	B
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	One-Time Inspection (B.2.3.20)	VIII.C.SP-88	3.4.1-011	A

Table 3.4.2-6: Turbine Generator – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Valve Body	Leakage Boundary	Stainless Steel	Treated Water >140 F (Internal)	Cracking	Water Chemistry (B.2.3.2)	VIII.C.SP-88	3.4.1-011	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG 2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

3.5 AGING MANAGEMENT OF CONTAINMENTS, STRUCTURES, AND COMPONENT SUPPORTS

3.5.1 Introduction

This section provides the results of the AMR for those components identified in Section 2.4, *Scoping and Screening Results: Structures*, as being subject to AMR. The structures or structural components that are addressed in this section are described in the indicated sections.

- Primary Containment (2.4.1)
- Cranes, Heavy Loads, Rigging (2.4.2)
- Diesel Fuel Oil Transfer House (2.4.3)
- Emergency Diesel Generator Building (2.4.4)
- Emergency Filtration Train Building (2.4.5)
- Fire Protection Barrier and Commodity Group (2.4.6)
- Hangers and Supports Commodity Group (2.4.7)
- High Pressure Coolant Injection Building (2.4.8)
- Intake Structure (2.4.9)
- Miscellaneous Station Blackout Yard Structures (2.4.10)
- Off-Gas Stack (2.4.11)
- Off-Gas Storage and Compressor Building (2.4.12)
- Plant Control and Cable Spreading Structure (2.4.13)
- Radioactive Waste Building (2.4.14)
- Reactor Building (2.4.15)
- Structures Affecting Safety (2.4.16)
- Turbine Building (2.4.17)
- Underground Duct Bank (2.4.18)

3.5.2 Results

Table 3.5.2-1, Primary Containment – Summary of Aging Management Evaluation

Table 3.5.2-2, Cranes, Heavy Loads – Summary of Aging Management Evaluation

Table 3.5.2-3, Diesel Fuel Oil Transfer House – Summary of Aging Management Evaluation

Table 3.5.2-4, Emergency Diesel Generator Building – Summary of Aging Management Evaluation

Table 3.5.2-5, Emergency Filtration Train Building – Summary of Aging Management Evaluation

Table 3.5.2-6, Fire Protection Barrier and Commodity Group – Summary of Aging Management Evaluation

Table 3.5.2-7, Hangers and Supports Commodity Group – Summary of Aging Management Evaluation

Table 3.5.2-8, High Pressure Coolant Injection Building – Summary of Aging Management Evaluation

Table 3.5.2-9, Intake Structure – Summary of Aging Management Evaluation

Table 3.5.2-10, Miscellaneous Station Blackout Yard Structures – Summary of Aging Management Evaluation

Table 3.5.2-11, Off-Gas Stack – Summary of Aging Management Evaluation

Table 3.5.2-12, Off-Gas Storage and Compressor Building – Summary of Aging Management Evaluation

Table 3.5.2-13, Plant Control and Cable Spreading Structure – Summary of Aging Management Evaluation

Table 3.5.2-14, Radioactive Waste Building – Summary of Aging Management Evaluation

Table 3.5.2-15, Reactor Building – Summary of Aging Management Evaluation

Table 3.5.2-16, Structures Affecting Safety – Summary of Aging Management Evaluation

Table 3.5.2-17, Turbine Building – Summary of Aging Management Evaluation

Table 3.5.2-18, Underground Duct Bank – Summary of Aging Management Evaluation

3.5.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.5.2.1.1 Primary Containment

Materials

The materials of construction for the PCT structure and internal structural components are:

- Coatings
- Concrete (Reinforced)
- Dissimilar Metal Welds
- Elastomer, Rubber, and Other Similar Materials
- Inconel
- Lubrite®
- Stainless Steel
- Steel

Environments

The PCT structure and internal structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Concrete
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the PCT structure and internal structural components require management:

- Cracking
- Cumulative Fatigue Damage
- Loss of Bond
- Loss of Coating or Lining Integrity
- Loss of Leak Tightness
- Loss of Material
- Loss of Mechanical Function
- Loss of Mechanical Properties
- Loss of Preload
- Loss of Sealing
- Reduction of Strength

Aging Management Programs

The following AMPs manage the aging effects for the primary containment structure and internal structural components:

- 10 CFR Part 50, Appendix J (B.2.3.31)
- ASME Section XI, Subsection IWE (B.2.3.29)
- ASME Section XI, Subsection IWF (B.2.3.30)
- Protective Coating Monitoring and Maintenance (B.2.3.35)
- Structures Monitoring (B.2.3.33)
- TLAA - Section 4.5, *Containment Liner Plate, Metal Containments and Penetrations Fatigue*
- Water Chemistry (B.2.3.2)

3.5.2.1.2 Cranes, Heavy Loads, Rigging

Materials

The materials of construction for the Cranes, Heavy Loads, Rigging structural components are:

- Aluminum
- Steel

Environments

The Cranes, Heavy Loads, Rigging structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Cranes, Heavy Loads, Rigging structural components require management:

- Cracking
- Cumulative Fatigue Damage
- Loss of Material
- Loss of Preload

Aging Management Programs

The following AMPs manage the aging effects for the Cranes, Heavy Loads, Rigging structural components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)
- One-Time Inspection (B.2.3.20)
- Water Chemistry (B.2.3.2)
- TLAA – Section 4.6.1, *Fatigue of Cranes (Crane Cycle Limits)*

3.5.2.1.3 Diesel Fuel Oil Transfer House

Materials

The materials of construction for the Diesel Fuel Oil Transfer House structural components are:

- Concrete (Reinforced)
- Steel

Environments

The Diesel Fuel Oil Transfer House structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The Diesel Fuel Oil Transfer House structural components are exposed to the following environments:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of material
- Loss of preload
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the Diesel Fuel Oil Transfer House structural components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.4 Emergency Diesel Generator Building

Materials

The materials of construction for the DGB structural components are:

- Concrete Block
- Concrete (Reinforced)
- Elastomer
- Grout
- Steel

Environments

The DGB structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the DGB structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond

- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength
- Reduction In Concrete Anchor Capacity

Aging Management Programs

The following AMPs manage the aging effects for the DGB structural components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.5 Emergency Filtration Train Building

Materials

The materials of construction for the EFB structural components are:

- Concrete (Reinforced)
- Elastomer
- Steel

Environments

The EFB structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the EFB structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the EFB structural components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.6 Fire Protection Barrier and Commodity Group

Materials

The materials of construction for the Fire Protection Barriers Commodity Group structural components are:

- Aluminum
- Cementitious
- Concrete Block
- Concrete (Reinforced)
- Elastomer
- Silicates
- Steel

Environments

The Fire Protection Barriers Commodity Group structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor

Aging Effects Requiring Management

The following aging effects associated with the Fire Protection Barriers Commodity Group structural components require management:

- Change In Material Properties
- Cracking
- Hardening
- Loss of Material
- Loss of Strength
- Shrinkage

Aging Management Programs

The following AMPs manage the aging effects for the Fire Protection Barriers Commodity Group structural components:

- Fire Protection (B.2.3.15)
- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.7 Hangers and Supports Commodity Group

Materials

The materials of construction for the Hangers and Supports structural components are:

- Aluminum
- Concrete (Reinforced)
- Elastomer
- Fiberglass
- Grout
- Lubrite
- Stainless Steel
- Steel

Environments

The Hangers and Supports structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Treated Water
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Hangers and Supports structural components require management:

- Cracking
- Crazing
- Dimensional Change
- Discoloration
- Hardening
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Mechanical Function
- Loss of Preload
- Loss of Strength
- Reduced Thermal Insulation Resistance
- Reduction In Concrete Anchor Capacity
- Reduction or Loss of Isolation Function
- Scuffing
- Shrinkage
- Surface Cracking

Aging Management Programs

The following AMPs manage the aging effects for the Hangers and Supports structural components:

- ASME Section XI, Subsection IWF (B.2.3.30)
- External Surfaces Monitoring of Mechanical Components (B.2.3.23)
- Structures Monitoring (B.2.3.33)
- Water Chemistry (B.2.3.2)

3.5.2.1.8 High Pressure Coolant Injection Building

Materials

The materials of construction for the HPCI Building structural components are:

- Aluminum
- Concrete (Reinforced)
- Elastomer
- Steel

Environments

The HPCI Building structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the HPCI Building structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the HPCI Building structural components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.9 Intake Structure

Materials

The materials of construction for the INS structural components are:

- Concrete Block
- Concrete (Reinforced)
- Elastomer
- Steel

Environments

The INS structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the INS structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the INS structural components:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)
- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.10 Miscellaneous Station Blackout Yard Structures

Materials

The materials of construction for the miscellaneous SBO yard structures' structural components are:

- Concrete Block
- Concrete (Reinforced)
- Steel

Environments

The miscellaneous SBO yard structures' structural components are exposed to the following environments:

- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the miscellaneous SBO yard structures' structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the miscellaneous SBO yard structures' structural components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.11 Off-Gas Stack

Materials

The materials of construction for the off-gas stack structural components are:

- Concrete Block
- Concrete (Reinforced)

- Stainless Steel
- Steel

Environments

The Off-gas stack structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the off-gas stack structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the off-gas stack structural components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.12 Off-Gas Storage and Compressor Building

Materials

The materials of construction for the Off-Gas Storage and Compressor Building structural components are:

- Concrete (Reinforced)
- Steel

Environments

The Off-Gas Storage and Compressor Building structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor

- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Off-Gas Storage and Compressor Building structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the Off-Gas Storage and Compressor Building structural components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.13 Plant Control and Cable Spreading Structure

Materials

The materials of construction for the plant control and cable spreading structure's structural components are:

- Concrete Block
- Concrete (Reinforced)
- Elastomer
- Steel

Environments

The plant control and cable spreading structure's structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the plant control and cable spreading structure's structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the plant control and cable spreading structure's structural components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.14 Radioactive Waste Building

Materials

The materials of construction for the Radioactive Waste Building structural components are:

- Concrete Block
- Concrete (Reinforced)
- Elastomer
- Glass
- Steel

Environments

The Radioactive Waste Building structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Radioactive Waste Building structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the Radioactive Waste Building structural components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.15 Reactor Building

Materials

The materials of construction for the Reactor Building structural components are:

- Aluminum
- Boral
- Concrete Block
- Concrete (Reinforced)
- Elastomer
- Glass
- Stainless Steel
- Steel

Environments

The Reactor Building structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Treated Water
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Reactor Building structural components require management:

- Change In Dimensions
- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength
- Reduction of Neutron-Absorbing Capacity

Aging Management Programs

The following AMPs manage the aging effects for the Reactor Building structural components:

- Masonry Walls (B.2.3.32)
- Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.3.26)
- One-Time Inspection (B.2.3.20)
- Structures Monitoring (B.2.3.33)
- Water Chemistry (B.2.3.2)

3.5.2.1.16 Structures Affecting Safety

Materials

The materials of construction for the structures affecting safety structural components are:

- Concrete (Reinforced)
- Steel

Environments

The structures affecting safety structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the structures affecting safety structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the structures affecting safety structural components:

- Structures Monitoring (B.2.3.33)

3.5.2.1.17 Turbine Building

Materials

The materials of construction for the Turbine Building structural components are:

- Aluminum
- Concrete Block
- Concrete (Reinforced)
- Elastomer
- Grout
- Steel

Environments

The Turbine Building structural components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the Turbine Building structural components require management:

- Cracking
- Distortion

- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Sealing
- Loss of Strength
- Reduction In Concrete Anchor Capacity

Aging Management Programs

The following AMPs manage the aging effects for the Turbine Building structural components:

- Masonry Walls (B.2.3.32)
- Structures Monitoring (B.2.3.33)

3.5.2.1.18 Underground Duct Bank

Materials

The materials of construction for the underground duct bank structural components are:

- Concrete (Reinforced)
- Steel

Environments

The underground duct bank structural components are exposed to the following environments:

- Air - Outdoor
- Groundwater/Soil
- Water - Flowing

Aging Effects Requiring Management

The following aging effects associated with the underground duct bank structural components require management:

- Cracking
- Distortion
- Increase in Porosity and Permeability
- Loss of Bond
- Loss of Material
- Loss of Preload
- Loss of Strength

Aging Management Programs

The following AMPs manage the aging effects for the underground duct bank structural components:

- Structures Monitoring (B.2.3.33)

3.5.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2192 provides the basis for those AMPs/topics that warrant further evaluation by the reviewer in the SLRA. For the containment and plant structures and structural commodities and structural system those programs/issues are addressed in the following sections. Italicized text is taken directly from NUREG-2192.

3.5.2.2.1 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 Sub-Foundations

Cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Code Section XI, Subsection IWL to manage these aging effects. Also, reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. The existing program relies on the structures monitoring program to manage these aging effects. However, some plants may rely on a dewatering system to lower the site groundwater level. If the plant's current licensing basis (CLB) credits a dewatering system to control settlement, further evaluation is recommended to verify the continued functionality of the dewatering system during the subsequent period of extended operation.

As summarized in items 3.5.1-001 and 3.5.1-002, respectively, cracking and distortion due to increased stress levels from settlement and reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete sub-foundations are not applicable to the MNGP Mark I steel containment. The primary containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building and supported by the Reactor Building basemat. As such, the primary containment structure internal concrete is not exposed to groundwater/soil environments and cannot settle independently of the basemat. Furthermore, consistent with NUREG-1865, Section 3.5.2.2.1, and as reiterated in Section 3.5.2.2.1.3 below, MNGP buildings do not have porous sub-foundations and a de-watering system is not relied on. Lastly, consistent with NUREG-1865, MNGP 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 (as supplemented by SLR-ISG-2021-03-STRUCTURES)

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a and ASME Code Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3440 of ASME Code Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects for portion of the concrete containment components that exceed specified temperature limits {i.e., general area temperature greater than 66 degrees Celsius (150 degrees Fahrenheit) and local area temperature greater than 93 degrees Celsius (200 degrees Fahrenheit). Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. Acceptance criteria are described in Branch Technical Position (BTP) RLSB (License Renewal and Standardization Branch)-1, "Aging Management Review – Generic, July 2017" (Appendix A.1 of this SRP-SLR).

Elevated temperature impacts on concrete were addressed during the initial license renewal. This aging effect mainly concerns PWR and BWR Mark II and III concrete containments; however, the temperature criteria presented in this section apply to all concrete. Plant documents confirm that concrete elements are not subject to elevated temperatures in excess of 150°F generally and 200°F locally. Plant areas that bound high temperature considerations are the drywell general area and biological shield wall piping penetration local area, which experience temperatures of 135°F and 179°F, respectively. Additionally, normal temperature, pressure, and humidity conditions either do not significantly change due to the EPU or remain bounded by values used in the current analysis

As summarized in item 3.5.1-003, reduction of strength and modulus of concrete due to elevated temperatures is not applicable to the MNGP Mark I steel containment. The bulk drywell temperature is maintained by the primary containment ventilating and cooling system. The average air temperature inside the drywell during normal plant operation is limited to 135°F. Therefore, concrete structural components located inside the drywell are not subject to general area temperatures greater than 150°F.

Surrounding the reactor vessel and supported on the reactor vessel pedestal is the biological shield whose primary function is to protect equipment inside the drywell against radiation and thermal effects. Local area temperature in the biological shield wall due to hot reactor REC System penetrations is calculated at 179°F; less than the concrete degradation threshold of 200°F. Consistent with NUREG-1865, thermal insulation is credited with maintaining the temperatures in the bioshield wall below 200°F and are therefore within the scope of license renewal and subject to an AMR as described in Table 3.5.2-7.

3.5.2.2.1.3. Loss of Material Due to General, Pitting, and Crevice Corrosion

(1) Loss of material due to general, pitting, and crevice corrosion could occur in steel elements of inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J AMPs, to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is indicated from the IWE examinations. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

As summarized in items 3.5.1-004, 3.5.1-005, and 3.5.1-035 loss of material due to general, pitting, and crevice corrosion of steel elements in inaccessible areas is not applicable to the MNGP Mark I steel containment.

The MNGP primary containment design includes an accessible moisture barrier at the concrete floor to drywell shell interface perimeter and includes an inaccessible sheet metal cover and joint sealing compound above the sand pocket region on the exterior of the drywell shell. The ASME Section XI, Subsection IWE (B.2.3.29) AMP performs an examination of the accessible moisture barrier at the concrete to shell interface for wear, damage, erosion, tears, cracks, or other defects that may violate the leak-tight integrity. There has been no corrosion detected at the moisture barrier at the bottom of the drywell interior.

The MNGP primary containment design includes an inaccessible 2-inch air gap between the exterior steel drywell surface and the concrete sacrificial shield. MNGP has three drainage paths for removing leakage into the drywell air gap. The first path prevents leakage past the refueling bellows from entering the air gap. This consists of a drain line located below the bellow's non-wetted side (i.e. FPW7-8" to FPW7-4" with flow switch FS-2792 to light panel C65 located on operating floor to alarm on panel C04 located in the MCR). The second path is the air gap to sand pocket interface where there is a galvanized steel plate which is sealed to the drywell shell. Four-inch drain lines are provided to remove water that might collect on the plate from above. The third pathway is from the sand pocket itself, which is provided with four, 2-inch drain lines. To provide reasonable assurance that moisture is not present in the air gap region of the steel drywell, the ASME Section XI, Subsection IWE (B.2.3.29) AMP monitors for blockage and leakage of the drywell air gap and sand pocket drain line outlets during each outage when the refueling cavity is flooded. The drywell to reactor building refueling seal is addressed as part of the Reactor Building.

Loss of material due to general, pitting, and crevice corrosion in inaccessible areas of the steel containment will be managed by the ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31) AMPs during the SPEO, and a separate, plant-specific AMP is not required.

(2) Loss of material due to general, pitting, and crevice corrosion could occur in steel torus shell of Mark I containments. The existing program relies on ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J, to manage this aging effect. If corrosion is significant,

recoating of the torus is recommended. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

As summarized in item 3.5.1-006, the ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31) AMPs will be used to manage the loss of material of steel elements in the torus shell.

During base metal examinations associated with the torus coating project in March 2007, arc strikes were noted on the interior of the torus shell. These arc strikes occurred during construction and only became visible after all coating was removed. The scheduled IWE examinations confirmed the superficial nature of these arc strikes (i.e., the thickness of the torus shell is acceptable).

Underwater torus coatings are inspected periodically. No metal loss was reported during the visual inspection performed during RFO 25. During RFO 26, the deepest pit noted during the inspection of the underwater portion of the torus shell was 18 mils, which is substantially below the deepest allowable local pit on the lower half of the torus shell. Subsequent inspections of the underwater portion yielded similar results.

Examinations conducted in accordance with ASME Section XI, Subsection IWE have not identified significant corrosion in the steel torus shell of the MNGP Mark I containment.

(3) Loss of material due to general, pitting, and crevice corrosion could occur in steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and interior surface of suppression chamber shell of Mark III containments. The existing program relies on ASME Code Section XI, Subsection IWE to manage this aging effect. Further evaluation is recommended of plant-specific programs to manage this aging effect if corrosion is significant. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

As summarized in item 3.5.1-007, the ASME Section XI, Subsection IWE (B.2.3.29) AMP will be used to manage the loss of material of steel torus ring girders and downcomers during the SPEO.

Steel torus ring girders and downcomers of the MNGP 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 the torus ring girders and downcomers that has identified significant loss of material due to pitting and crevice corrosion as a result of exposure to air – indoor and treated water. The interior surface of the Bay 6 downcomer coating exhibited delamination/flaking coating during the RFO 30 inspection. This coating degradation was identified during previous inspections and has not changed significantly since. Bay 11, interior downcomers vapor area inspection showed weld burns and pinpoint rusting. Similarly, there were no significant changes since the previous inspection.

The ASME Section XI, Subsection IWE (B.2.3.29) AMP is used to manage loss of material due to corrosion of the steel torus ring girders and downcomers during the SPEO and a plant-specific AMP is not required.

3.5.2.2.1.4. Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevation Temperature

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.5, "Concrete Containment Unbonded Tendon Pre-Stress Analysis," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of the SRP-SLR).

As summarized in item 3.5.1-008, loss of prestress due to relaxation, shrinkage, creep, and elevated temperature is not applicable to the MNGP Mark I steel containment. This aging effect is only applicable to 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, control rod drive (CRD) hatch, penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers may be TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed in Section 4.6, "Containment Liner Plates, Metal Containments, and Penetrations Fatigue Analysis," and for cases of plant-specific components, in Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

For the above-stated containment pressure-retaining components (corresponding to Table 3.5-1, Items 027 and 040) subject to cyclic loading for which no CLB fatigue analysis exists at the time of an SLRA submittal, a plant-specific further evaluation may be performed to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for the component. As one acceptable approach, the aging effect does not require aging management actions if the further evaluation demonstrates that the six criteria for cyclic loading in paragraph NE-3222.4(d) (NE-3221.5(d) in 1980 and later code editions), "Analysis for Cyclic Operation, Vessels Not Requiring Analysis for Cyclic Service," of ASME Code, Section III, Division 1 (1974 edition or later edition incorporated by reference in 10 CFR 50.55a(a)(i)), that provide for a waiver from detailed fatigue analysis are satisfied for applicable component materials through the *end of the subsequent period of extended operation. The option to perform a fatigue waiver analysis to address the aging effect of cracking due to cyclic loading, for specific containment metallic components, is in lieu of performing supplemental surface examinations or performing or crediting an appropriate 10 CFR Part 50, Appendix J, leak-rate test discussed in GALL-SLR Report AMP XI.S1, "ASME Section XI, Subsection IWE."*

As summarized in item 3.5.1-009 cumulative fatigue damage is identified as a TLAA in Section 4.5. Components with an existing CLB fatigue analysis include the downcomers, torus penetrations, torus shell, ECCS suction header, vent header, vent lines, and vent line bellows, as well as drywell penetration bellows (hot pipe penetration bellows) and refueling bellows skirt (the limiting condition for the drywell to reactor building refueling seal and RPV to drywell refueling seal).

As described in the 2005 LRA, "Licensing and design basis documents do not reflect the existence of any fatigue analysis for the drywell shell plates, drywell penetrations, and drywell penetration sleeves. These components and associated dissimilar metal welds are designed to stress levels without requiring a fatigue analysis. In addition, these components were not evaluated for fatigue in the original design, and the Plant Unique Analysis (PUA) did not re-evaluate them for fatigue." Review of some key license amendments subsequent to the renewed license (e.g., EPU, MELLLA+, AST) confirms that components were not re-evaluated for fatigue. The MNGP drywell shell, drywell penetrations, and penetration sleeves were determined not to have an existing CLB fatigue analysis and therefore have no fatigue TLAAs. In addition, non-piping penetrations (CRD hatch, equipment hatch, personnel airlocks, electrical penetrations, and seismic restraint inspection ports) are considered not to have a CLB fatigue evaluation.

An assessment was performed which concluded that the drywell shell and non-high temperature drywell penetrations are subjected to a small and acceptable amount of fatigue, therefore, fatigue analysis, or a fatigue waiver, for the drywell shell and drywell penetrations is not required. The assessment did not include drywell penetration bellows, which have fatigue analysis, and penetration adapters of high temperature drywell mechanical penetrations.

As summarized in items 3.5.1-027, and 3.5.1-040, cracking due to cyclic loading is not an aging effect requiring management for the drywell shell, non-high temperature drywell penetrations and penetration sleeves. 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.2.3.29) AMP, including an enhancement to inspect accessible portions for cracking, and 10 CFR Part 50, Appendix J (B.2.3.31) AMP, respectively, during the SPEO.

3.5.2.2.1.6. Cracking Due to Stress Corrosion Cracking

Stress corrosion cracking (SCC) of stainless steel (SS) penetration sleeves, penetration bellows, vent line bellows, suppression chamber shell (interior surface), and dissimilar metal welds could occur in PWR and/or BWR *containments. The existing program relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, to manage this aging effect. Further evaluation, including consideration of SCC susceptibility and applicable operating experience (OE) related to detection, is recommended of additional appropriate examinations/evaluations implemented to detect this aging effect for these SS components and dissimilar metal welds.*

As summarized in items 3.5.1-010, 3.5.1-038, and 3.5.1-039, cracking due to SCC is an applicable aging effect when stainless steel or nickel alloy components are exposed to temperatures in excess of 140°F. Stainless steel or nickel alloy components of the primary containment include: Torus thermowells, electrical penetration canisters, certain piping penetration manifold plates/spare penetration nozzles/TIP drive penetration nozzles, personnel airlock leakage test connections, and hot piping penetration double ply expansion bellows. Connection of these stainless steel or nickel alloy components to the steel drywell or torus involve dissimilar metal welds (DMWs). Of these, only expansion bellows may experience temperatures in excess of 140°F during normal operation.

MNGP containment high temperature fluid penetrations have a guard pipe between the hot line and the penetration nozzle in addition to a double-seal arrangement. The penetration sleeve is welded to the drywell and extends through the biological shield (sacrificial shield) where it is welded to a bellows which in turn is welded to the guard pipe. The bellows accommodate the thermal expansion of the drywell. Bellows are fabricated from stainless steel, and in one instance Inconel (nickel alloy).

The following primary containment penetrations, equipped with stainless steel or nickel alloy bellows, are subject to elevated temperatures during normal operation:

Penetration Number	Description
X-7A	Primary Steam Line A
X-7B	Primary Steam Line B
X-7C	Primary Steam Line C
X-7D	Primary Steam Line D
X-8	Primary Steam Drain
X-9A	Feedwater Line
X-9B	Feedwater Line
X-10	Steam to RCIC
X-11	Steam to HPCI
X-12	RHR Supply
X-13A	LPCI to B Loop (RHR Return)
X-13B	LPCI to A Loop (RHR Return)
X-14	RWCU Supply
X-15	RWCU Return
X-16A	Core Spray B
X-16B*	Core Spray A

* MNGP replaced the double ply bellows on core spray penetration X16B after finding cracks during local leakage rate testing in the 1996 refueling outage. The replacement was done during the 1998 refueling outage. The original bellows was fabricated from austenitic stainless steel; the replacement is Inconel.

The suppression chamber and drywell shells at MNGP, as well as penetration nozzles, sleeves, etc., are made of carbon steel and not susceptible to SCC.

Cracking due to SCC of stainless steel (SS) or nickel alloy (NA) penetration bellows (hot fluid penetrations), and associated DMWs will be managed by the ASME Section XI, Subsection IWE (B.2.3.29) AMP and the 10 CFR Part 50, Appendix J (B.2.3.31) AMP, as clarified below. 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. Furthermore, the vent system also provides support for a portion of the SRV piping inside the vent line and suppression chamber. Loads which act on the SRV piping are transferred to the vent system by the penetration assembly which is welded to the vent. As such, the ASME Section XI, Subsection IWE (B.2.3.29) AMP will be enhanced to include one-time volumetric/surface examination of 20 percent of these 24 penetration bellows (i.e., 5 inspections). In addition, due to being higher temperature, these penetrations are also leading indicators for cyclic load cracking of other susceptible drywell shell, penetration sleeve or other locations.

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 A.1 of this SRP-SLR).

As summarized in item 3.5.1-011, loss of material (scaling, spalling) and cracking due to freeze-thaw is not applicable to the MNGP Mark I steel containment. The primary containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building. Primary containment structure internal concrete is not exposed to air - outdoor, or groundwater/soil environments. (NF-36169, NF-36054, and USAR Section 12.2.2.1.1) In addition, freeze-thaw of Reactor Building concrete is addressed in Section 3.5.2.2.2.1, item 1, and item 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 A.1 of this SRP-SLR).

As summarized in item 3.5.1-012, cracking due to expansion from reaction with aggregates is not applicable to the MNGP Mark I steel containment. The primary containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building.

The primary containment internal concrete elements are classified as Group 4 Structures. Cracking due to expansion from reaction with aggregates for the primary containment internal concrete elements and Reactor Building concrete is addressed in Section 3.5.2.2.2.1, item 2 and 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 to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

As summarized in item 3.5.1-014, increase in porosity and permeability due to leaching of calcium hydroxide and carbonation is not applicable to the MNGP Mark I steel containment. The primary containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building. Primary containment structure internal concrete elements are not exposed to air - outdoor or groundwater/soil environments where leaching could occur. Leaching of calcium hydroxide and carbonation has not been observed in accessible concrete internal to the primary containment structure. In addition, leaching of Reactor Building concrete is addressed in Section 3.5.2.2.2.1, item 4 and 3.5.1-047.

3.5.2.2.2 Non-Containment Plant Structures

3.5.2.2.2.1. Aging Management of Inaccessible Areas

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1–3, 5 and 7–9 structures. Further evaluation is recommended of inaccessible areas of these Groups of structures for plants located in moderate to severe weathering conditions to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5-1, item number 3.5.1-042: This aging effect and mechanism, the loss of material (spalling, scaling) and cracking due to freeze-thaw, is applicable to MNGP reinforced concrete structures. For MNGP, the winter water table at structure locations are well below the depth of frost penetration. Consequently, freezing of ground water in contact with concrete is not a concern. For this reason, the ensuing discussion covers only the below grade zone above the water table. Concrete air content, (as determined by both design mix and production batch tests ranges from somewhat over 3 percent to just below 6 percent. Therefore, in accordance with NUREG-2192, aging management to address freeze-thaw effects is required only for accessible concrete surfaces. Inaccessible concrete requires evaluation only in the event that examinations uncover freeze-thaw damage in accessible areas. If freeze thaw damage were to occur, it would likely 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. 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. MNGP exterior concrete has been exposed to severe winter conditions for many years and has, to date, shown no signs of significant freeze-thaw damage. While loss of material and cracking of concrete due to freeze-thaw are not probable, Group 1 through 3, 5, and 9 structures at MNGP are located in a “severe” weathering region per Figure 1 of American Society for Testing of Materials (ASTM) C33, *Location of Weathering Regions.* As such, consistent with the initial LR, the MNGP Structures Monitoring (B.2.3.33) AMP inspects for concrete aging effects related to freeze-thaw, should it occur. Additionally, the MNGP Structures Monitoring (B.2.3.33) AMP opportunistic inspections confirm the absence of aging effects by examining normally inaccessible structural components, when scheduled maintenance work and planned plant modifications permit access and will evaluate observed aging effects in accessible areas that could be indicative of degradation in inaccessible areas.

(2) *Cracking due to expansion and reaction with aggregates could occur in inaccessible concrete areas for Groups 1–5 and 7–9 structures. Further evaluation is recommended of inaccessible areas of these Groups of structures to determine the need for a plant-specific AMP or plant-specific enhancements to the Structures Monitoring AMP, is required 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 3.5.1-043: This aging effect and mechanism, cracking due to expansion and reaction with aggregates, is considered applicable to MNGP reinforced concrete structures. Group 1 through 3, 5, and 9 structures at MNGP are designed and constructed in accordance with ACI 201.2R-77 using ingredients/materials conforming to ACI and ASTM standards. Concrete aggregates conform to the requirements of ASTM C33, *Standard Specification of Concrete Aggregates.* Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment, and organic matter. Tests and petrographic examinations performed according to ASTM C289-64 and ASTM C295 verified that aggregates used are not reactive. For initial LR, the NRC determined that cracking due to reaction with aggregates would be adequately managed. OE has not identified any evidence of reaction with aggregates at MNGP. Additionally, the MNGP Structures Monitoring AMP (B.2.3.33) has been refined, based on industry/fleet information, to include visual examination for unique "map" or "cracking" that would be indicative of reaction with aggregates, such as alkali-silica reaction (ASR), and includes opportunistic inspection of below-grade inaccessible concrete areas for MNGP Group 1 through 3, 5, and 9 structures. 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. If cracking due to expansion and reaction with aggregates were significant, pattern cracking would be expected over the accessible surfaces. This has not occurred. As such, a plant-specific program is not required to manage this aging effect; rather, cracking due to reaction with aggregates in inaccessible areas will be managed by the MNGP Structures Monitoring (B.2.3.33) AMP.

(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 sub foundations 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: MNGP does not rely on a dewatering system; thus, the Structures Monitoring (B.2.3.33) AMP will be used to manage cracking and distortion of the reinforced concrete elements of the MNGP structures founded on soil and/or exposed to a soil environment

Table 3.5-1, item number 3.5.1-046: The Structures Monitoring (B.2.3.33) AMP manages the aging effects in addition to monitoring for settlement and potential cracking. For SLR, groundwater is considered to be flowing water. Therefore, the identification of indications of settlement is included in the Structures Monitoring (B.2.3.33) AMP for MNGP Group 1 through 3, 5, and 9 structures. Additionally, as part of the Structures Monitoring (B.2.3.33) AMP, an annual inspection of the Diesel Fuel Oil Transfer House for settlement is performed to manage the aging effects of cracks, distortion, and increase in component stress level due to settlement.

With the exception of the Diesel Fuel Oil Transfer House and Off-Gas Storage Building HTV exhaust pipe, no significant settlement has been observed on any major structure and de-watering systems are not used. This satisfies NUREG-2192 condition requirements on concrete settlement, and therefore, with the exception of the Diesel Fuel Oil Transfer House, cracks, distortion, and increase in component stress levels due to settlement do not require aging management.

(4) *Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Groups 1–5 and 7–9 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).*

Table 3.5-1, item number 3.5.1-047: Group 1 through 3, 5, and 9 structures at MNGP are designed and constructed in accordance with ACI 201.2R-77 using ingredients/materials conforming to ACI and ASTM standards. Concrete aggregates conform to the requirements of ASTM C-33-64 (fine and coarse aggregate). Materials for concrete used in MNGP concrete SCs were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. MNGP foundation materials do not contain any porous layers. The concrete base or lean concrete fill material used beneath major building foundations did not include high-alumina cement. MNGP does not rely on a de-watering system to lower site ground water. MNGP OE does not indicate leaching has been observed on accessible concrete areas that would impact intended functions of the structure.

However, that notwithstanding, the foundations of MNGP groups 1 through 3, 5, and 9 plant structures are considered to be exposed to groundwater, which for SLR is considered to be flowing water. Periodic ground water level measurements and chemical analysis of ground water are performed to verify the associated chemistry remains non-aggressive as described in the Structures Monitoring (B.2.3.33) AMP. The frequency of monitoring ground water chemistry (pH, chlorides, and sulfates) is monthly. In addition, the Structures Monitoring (B.2.3.33) AMP includes opportunistic inspection of inaccessible concrete surfaces, when excavation for other reasons permits access. Accessible areas of concrete structures exposed to an outdoor air environment can be used as an indicator of concrete condition in a soil or groundwater environment. Any significant leaching or carbonation that is observed in accessible areas will be evaluated for the potential impact on the function of concrete in inaccessible areas.

3.5.2.2.2.2. Reduction of Strength and Modulus due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR Group 1–5 concrete structures. For any concrete elements that exceed specified temperature limits, further evaluations are recommended. Appendix A of American Concrete Institute (ACI) 349-85, "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 A.1 of this SRP-SLR).*

Table 3.5-1, item number 3.5.1-048: Reduction of strength and modulus of elasticity due to elevated temperatures of Class 1 structures was evaluated for the current renewed MNGP licenses and is addressed in NUREG-2192. For plant areas of concern temperatures are normally maintained below the specified limits.

Plant documents confirm that concrete elements are not subject to elevated temperatures in excess of 150°F general area and 200°F local area. Plant areas that bound high temperature considerations are the drywell general area and biological shield wall piping penetration local area, which experience temperatures of 135°F and 179°F respectively. Thermal insulation is credited with maintaining the temperatures in the biological shield wall.

Insulation (thermal) is conservatively included within the scope of SLR to assist in maintaining local concrete temperatures. The aging management of this insulation is provided by the MNGP External Surfaces of Mechanical Components (B.2.3.23) AMP. As such, a plant-specific program is not required.

3.5.2.2.2.3. Aging Management of Inaccessible Areas for Group 6 Structures

Further evaluation is recommended for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL-SLR Report AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," or Federal Energy Regulatory Commission (FERC)/U.S. Army Corp of Engineers dam inspection and maintenance procedures.

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is recommended 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 A1 of this SRP-SLR).

Further evaluation for Inaccessible Areas for Group 6 Structures is provided below:

Table 3.5-1 Item Number 3.5.1-049: Group 6 structures at MNGP are located in a "severe" weathering region per Figure 1 of ASTM C33, *Location of Weathering*

Regions. As such, consistent with the initial LR, the MNGP Structures Monitoring (B.2.3.33) AMP would detect concrete aging effects related to freeze-thaw, should it occur. Cracking, spalling and disintegration of concrete due to freeze-thaw cycling are concrete aging effects requiring management in the atmosphere/weather environment. In addition, loss of material (disintegration of concrete) and corrosion of reinforcing steel (with consequent spalling of concrete) due to the action of deicing salts is an aging effect requiring management in the localized area of the INS and Tunnel roof slabs.

The principal tool for managing these effects is examinations performed as required by the Structures Monitoring (B.2.3.33) AMP. A significant portion of the Group 6 structures at MNGP are accessible and provide indication of the condition of inaccessible portions of the structure.

In accordance with NUREG-2192, concrete located exterior and above grade in accessible areas (i.e., exposed to atmosphere/weather environment) is managed for the aging effects:

- Loss of material (spalling, scaling) and cracking due to freeze thaw
- Loss of material (spalling, scaling) and cracking due to de-icing salts
- Increase in porosity, permeability, and loss of strength due to leaching of calcium hydroxide
- Expansion and cracking due to reaction with aggregates
- Cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel
- Cracking, loss of bond, loss of material (spalling, scaling) due to de-icing salts
- Increase in porosity and permeability, cracking, loss of material due to aggressive chemical attack
- Reduction in concrete anchor capacity due to local concrete degradation/ Service-induced cracking or other concrete aging mechanisms

Additionally, the MNGP Structures Monitoring (B.2.3.33) AMP opportunistic inspections confirm the absence of aging effects by examining normally inaccessible structural components, when scheduled maintenance work and planned plant modifications permit access and will evaluate observed aging effects in accessible areas that could be indicative of degradation in inaccessible areas.

(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: The Group 6 structures at MNGP are designed and constructed in accordance with ACI 201.2R-77 using ingredients/materials conforming to ACI and ASTM standards. Concrete aggregates conform to the requirements of ASTM C33, *Standard Specification of Concrete Aggregates.* Water used for mixing concrete or processing concrete aggregates is free from any injurious amounts of acid, alkali, salts, oil, sediment, and organic matter. Tests and petrographic examinations performed according to ASTM C289-64 and ASTM C295 verified that aggregates used are not reactive. For initial LR, the NRC determined that cracking due to reaction with aggregates would be adequately managed. OE has not identified any evidence of reaction with aggregates at MNGP. However, based on industry/fleet OE, cracking due to expansion and reaction with aggregates is an applicable aging effect in below-grade inaccessible concrete areas for MNGP Group 6 structures and will be managed by the MNGP Inspections of Water-Control Structures Associated with Nuclear Power Plants AMP through the Structures Monitoring (B.2.3.33) AMP. A plant-specific AMP is not required.

(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 if a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5-1, item number 3.5.1-051: The Groups 6 structures at MNGP are designed and constructed in accordance with ACI 201.2R-77 using ingredients/materials conforming to ACI and ASTM standards. Concrete aggregates conform to the requirements of ASTM C-33-64 (fine and coarse aggregate). Materials for concrete used in MNGP concrete SCs were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. MNGP foundation materials do not contain any porous layers. The concrete base or lean concrete fill material used beneath major building foundations did not include high-alumina cement. MNGP does not rely on a de-watering system to lower site ground water.

However, that notwithstanding, the foundations of MNGP Group 6 plant structures are considered to be exposed to groundwater, which for SLR is considered to be flowing water. Periodic ground water level measurements and chemical analysis of ground water are performed to verify the associated chemistry remains non-aggressive as described in the Structures Monitoring (B.2.3.33) AMP. The frequency of monitoring ground water chemistry (pH, chlorides, and sulfates) is monthly. In addition, the Structures Monitoring (B.2.3.33) AMP includes opportunistic inspection of inaccessible concrete surfaces, when excavation for other reasons permits access, and evaluation of impact to inaccessible area intended functions if degradation, such as leaching or carbonation, is observed in an accessible area.

3.5.2.2.2.4. Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion

Cracking due to SSC and loss of material due to pitting and crevice corrosion could occur in (a) Group 7 and 8 SS tank liners exposed to standing water; and (b) SS and aluminum alloy support members; welds; bolted connections; or support anchorage to building structure exposed to air or condensation (see SRP-SLR Sections 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, and 3.2.2.2.10 for background information).

For Group 7 and 8 SS tank liners exposed to standing water, further evaluation is recommended of plant-specific programs to manage these aging effects. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

For SS and aluminum alloy support members; welds; bolted connections; support anchorage to building structure exposed to air or condensation, the plant-specific OE and condition of the SS and aluminum alloy components are evaluated to determine if the plant-specific air or condensation environments are aggressive enough to result in loss of material or cracking after prolonged exposure. The aging effects of loss of material and cracking in SS and aluminum alloy components is not applicable and does not require management if (a) the plant- specific OE does not reveal a history of pitting or crevice corrosion or cracking and (b) a one-time inspection demonstrates that the aging effects are not occurring or that an aging effect is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA. Visual inspections conducted in accordance with GALL-SLR Report AMP XI.M32, "One-Time Inspection," are an acceptable method to demonstrate that the aging effects are not occurring at a rate that affects the intended function of the components. One-time inspections are conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members; welds; bolted connections; or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, "ASME Section XI, Subsection IWF," or AMP XI.S6, "Structures Monitoring"); (b) conducting a representative sample inspection consistent with GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components;" or (c) developing a plant-specific AMP are acceptable programs to manage loss of material or cracking (as applicable). Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combinations which are not susceptible to SCC when used in structural support applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. For these alloys and tempers, the susceptibility of cracking due to SCC is not applicable. If these alloys or tempers have been used, the SLRA states the specific alloy or temper used for the applicable in-scope components.

Table 3.5-1, item number 3.5.1-052: This item is not applicable to MNGP. MNGP does not have Group 7 and 8 stainless steel tank liners exposed to standing water.

Table 3.5-1, item number 3.5.1-099: For stainless steel support members; welds; bolted connections; support anchorage to building structure exposed to air environments, this item number evaluates the components aligned to this item number for loss of material due to pitting and crevice corrosion and cracking due to SCC. The One-Time Inspection (B.2.3.20) AMP is credited to managing the cracking and loss of material for the aluminum fuel prep machine framing. The ASME Section XI, Subsection IWF (B.2.3.30) AMP will be used to examine the connections and supports aligned to this item number.

Table 3.5-1, Item Number 3.5.1-100: For stainless steel and aluminum components or connections exposed to air environments, this item number evaluates the components aligned to this item number for loss of material due to pitting and crevice corrosion and cracking due to SCC. The Structures Monitoring (B.2.3.33) AMP will continue to be used to examine the structural components and connections aligned to this item number. The Structures Monitoring (B.2.3.33) AMP requires periodic monitoring of ground/lake water chemistry to verify that it remains non-aggressive. Also, the air environment (and underground environment in manholes) for stainless steel supports or anchorage is not expected to be aggressive enough to cause cracking or localized loss of material for components (stainless steel new fuel storage racks, refueling cavity liner, component supports, anchorages, fire barrier penetration seals, insulation jacketing inside containment, aluminum insulation jacketing outside containment, and aluminum manway covers) exposed to indoor, outdoor, or underground air in the presence of wetting.

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 TLAAs as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.3, "Metal Fatigue Analysis," and/or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR. For plant-specific cumulative usage factor calculations, the method used is appropriately defined and discussed in the applicable TLAAs.

Table 3.5-1 item number 3.5.1-053: This item is not applicable at MNGP. The only fatigue analysis related to plant structures is for cranes and lifting devices and for portions of the primary containment. Management of cumulative fatigue damage to cranes and lifting devices is addressed in line item 3.3.1-001 and Section 4.6.1. Management of cumulative fatigue damage to primary containment is addressed in line item 3.5.1-009.

3.5.2.2.2.6. Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the sacrificial shield wall, and the reactor vessel support/pedestal structure. Data related to the effects and significance of neutron and gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light-water reactor (LWR) plants. However, based on literature review of existing research, radiation fluence limits of 1×10^{19} neutrons/cm^2 neutron radiation and 1×10^{8} Gy (1×10^{10} rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly (Ref. 17, 18, 19).

Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to selected existing AMPs to manage aging effects of irradiation if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy E >0.1 MeV) or gamma radiation exceeds the respective threshold level during the subsequent period that could affect intended functions. Higher fluence or dose levels may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and/or loss of mechanical properties of concrete from those fluence levels, at or above the operating temperature experienced by the concrete, and the effects are applied to the design calculations. Supporting calculations/analyses, test data, and other technical basis are provided to estimate and evaluate fluence levels and the plant-specific program. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

As summarized in Table 3.5-1, item 3.5.1-097, the potential for reduction of strength, loss of mechanical properties, and cracking due to irradiation of reinforced concrete is a concern for the biological shield around the reactor vessel and its support pedestal inside the drywell through the SPEO. Surrounding the reactor vessel and supported on the reactor vessel pedestal at elevation 947-ft 2-in is the biological shield whose primary function is to protect equipment inside the drywell against radiation and thermal effects. The biological shield is composed of two steel cylinders interconnected with columns and filled with concrete. Only the lower 12 feet of concrete, up to the 959-ft elevation, has been designed as structural concrete capable of resisting forces and shears. Above the 959-ft elevation the two steel cylinders and columns are structurally adequate, and the concrete fill has not been considered as adding to the support. The biological shield extends from elevation 947-ft 2-in to 993-ft 7-in (from RPV support pedestal to the seismic restraint above the RPV nozzle penetration). The biological shield concrete, like the reactor building concrete, is reinforced Type II Portland cement with a total air content of not less than 3 percent and not more than 5 percent by volume. The biological shield is approximately 26-in thick and consists of 27-in wide flange columns tied together by horizontal wide flange beams and ¼” steel plates. These plates are welded to the column flanges, both inside and outside, thereby forming a double walled shell.

The portion of the biological shield directly across from the active core will receive the maximum irradiation, which drops off significantly above and below the core. Irradiation effects on the biological shield concrete, the biological shield structural steel, and reactor vessel support structure inside the reactor cavity are evaluated below.

Neutron Fluence Biological Shield Irradiation Evaluation

Relative to neutron fluence, the maximum fluence level is 5.94 x 10^{18} n/cm^2 neutron radiation (fluence cutoff energy E >1 MeV) at the inside surface of the RPV at the beltline for the 72 Effective Full Power Years (EFPY) projected for the SPEO. The maximum estimated fluence levels at the biological shield concrete are based upon determining the attenuation through the intervening reactor vessel shell, air gap, and inner biological shield plate thickness and determining the neutron fluence levels at the energy levels of interest regarding potential concrete damage. Neutrons of sufficient energy collide with atoms in aggregates causing atomic displacement cascades, resulting in point defects that agglomerate to cause amorphization and nanovoid formation in mineral solids and lead to swelling after a nominal threshold of fluence is reached. The interaction of neutrons with crystalline solids is typically quantified as displacements per atom (dpa), which is a measure of the number of atomic displacements from equilibrium positions in the lattice per atom in the irradiated material due to elastic atomic collisions. In concrete, swelling of the aggregates puts the cement matrix in local tensile fields, adversely affecting the mechanical properties of the concrete. Furthermore, at high enough fluence, macroscopic swelling of the concrete occurs—which may affect the internal stress morphologies in structural elements. The majority of dpa damage (to concrete) is from neutrons with energies above 0.1 mega electron volts (MeV).

As such, it was necessary to determine the E >0.1 MeV fluence incident on the inner surface of the concrete. A bounding neutron fluence (E >0.1 MeV) was determined for the MNGP reactor biological shield concrete at 72 EFPY. The neutron source that was used to calculate the neutron fluence, as well as the gamma dose at 72 EFPY, for the biological shield concrete is the maximum-power reactor statepoint condition that was determined to occur in Cycle 28. The computational model that was used to perform the biological shield calculation was derived from the MNGP reactor fluence model and has been validated in accordance with the required benchmarks cited in U.S. NRC RG 1.190. The bounding fluence (E >0.1 MeV) incident in the inner surface of the biological shield concrete at 72 EFPY was determined to be 6.59 x 10^{18} neutrons per square centimeter (n/cm^2). In addition, Figure 5 of EPRI report 3002008128, Revision 0, July 2016, *Structural Disposition of Neutron Radiation Exposure in BWR Vessel Support Pedestals* records an 80-year reactor vessel outer diameter fluence (E >0.1 MeV) for MNGP of approximately 9.0 x 10^{18} n/cm^2. As such, the MNGP biological shield concrete fluence (E >0.1 MeV) through the SPEO is less than the recommended radiation fluence threshold of 1 *x* 10^{19} n/cm^2 for radiation damage to concrete.

Gamma Dose Biological Shield Irradiation Evaluation

Relative to the gamma dose incident on the biological shield concrete, the same calculation that determined the neutron fluence addressed above also determined the total gamma dose incident on the inner surface of the biological shield concrete. The bounding gamma dose for the MNGP biological shield concrete through 72 EFPY was determined to be 4.85×10^{10} rads. As such, the estimated 72 EFPY gamma dose incident on the inner surface of the biological shield concrete is greater than the recommended gamma radiation threshold, 1×10^{10} rads, for radiation damage to concrete.

Recent research on the gamma dose limit of 1×10^{10} rads reveals that this value may be overly conservative after subsequent reviews of previous test data. A recent paper published by I. Maruyama et al, Journal of Advanced Concrete Technology, Volume 15, 440-523 (2017), funded by the Japanese Regulator, concluded that there is no direct effect of gamma dose on concrete strength and recommends removing gamma dose limits. This paper concludes that previous studies that showed a decrease in concrete strength as a function of gamma dose were seeing an elevated temperature effect due to the high gamma flux in accelerated aging tests. Similar issues with the gamma dose limit of 1×10^{10} rad were also identified in NUREG/CR-7171, November 2013, *A Review of the Effects of Radiation on Microstructure and Properties of Concrete Used in Nuclear Power Plants*.

However, a separate analysis of the potential reduction in concrete strength due to gamma radiation above the recommended threshold has been completed for MNGP. This analysis considered attenuation through the concrete, and the potential for radiation induced volumetric expansion (RIVE) of the biological shield concrete thickness that is above the damage threshold, as well as the impact to gamma heating considerations.

As a result, the integrity of the biological shield is assured, and no additional aging management of the biological shield concrete beyond the current Structures Monitoring (B.2.3.33) AMP is necessary for aging effects due to irradiation during the SPEO. As such, there is reasonable assurance that a loss (or reduction) of concrete strength, loss of mechanical properties, and cracking will not affect the ability of the biological shield concrete to perform its component intended functions through the SPEO.

Reactor Vessel Support Steel Irradiation Evaluation

In addition to the potential aging effects due to irradiation of reinforced concrete, a loss (or reduction) in fracture toughness due to irradiation embrittlement of the reactor vessel support steel is a potential aging effect considered. The reactor vessel is shown in USAR Figures 3.6-2 and 4.2-1. The reactor vessel support structures at MNGP are described in USAR Section 4.2.2. The reactor vessel is supported by a steel skirt. The top of the skirt is welded to the bottom of the vessel. The skirt is then supported by a concrete and steel pedestal, which carries the load through the drywell to the reactor building foundation slab. Stabilizer brackets, located below the vessel flange, are connected to tension bars with flexible couplings. The bars are then connected to stabilizer brackets located on top of the biological shield wall to limit horizontal vibration and to resist seismic and jet reaction forces. The reactor pedestal is concrete with a ¼ in. steel liner on the exterior face. The reactor support skirt is bonded to the inside face. A 3-inch layer of pneumatically applied mortar covers the inside face of the skirt. As listed in Table 3.5.2-1, the reactor vessel support skirt is fabricated from steel. Also, the USAR Section 4.2.4.1 notes that the initial NDT temperature for the reactor vessel bottom head to which the support skirt is welded, is no higher than 40°F.

NUREG-1509, May 1996, *Radiation Effects on Pressure Vessel Supports*, is a resource for addressing irradiation embrittlement for SLR. NUREG-1509, Section 4.2.1 notes that radiation embrittlement is not an issue for reactor vessel support skirts. BWRVIP-342, *Aging Management of Reactor Vessel (RV) Supports for Extended operations*, 20222 (EPRI Report 3002020999), has recently been prepared to address irradiation of the RV support using the methodologies described in NUREG-1509.

As listed in Figure 3-1 of the EPRI document, MNGP is within the locus of GE-designed BWRs for which bounding design transients, maximum design loads and operating conditions are evaluated in the report. Furthermore, the 72 EFPY fast fluence (E >1 MeV) for the reactor vessel support skirt located well below the active fuel, as well as for the lateral supports located well above the active fuel, is estimated to remain below the 1 x 10^{17} n/cm^2 threshold for embrittlement of steel. Table 4.2.1.1-2 shows the reactor vessel beltline region. USAR Figure 4.2-1 shows the length of the reactor vessel and location of the active core. The radiation fields are significantly reduced above and below this region considering distance correction factors using the inverse square law as described in EPRI 3002008128. MNGP reactor vessel fluence calculations, projected for 72 EFPY, were performed using TransWare Radiation Analysis Modeling Application (RAMA) Fluence Methodology. In compliance with RG 1.190, TransWare has benchmarked the RAMA Fluence Methodology against industry standard benchmarks and plant-specific dosimetry measurements for BWRs and PWRs. The results of the benchmarking show that the fluence methodology implemented by TransWare is capable of predicting specimen activities with no discernable bias in the computed fluence. The fluence value (E >1 MeV) at 72 EFPY reported at a nozzle location below the reactor beltline is 3.25 x 10^{16} n/cm^2. The top portion (knuckle region) of the support skirt is approximately 11 feet below the bottom of active fuel. As such, the fluence (E >1 MeV) at the MNGP reactor vessel skirt is below the 1 x 10^{17} n/cm^2 (E >1 MeV) embrittlement threshold. Therefore, the conclusions of EPRI 300202099 are applicable to MNGP.

The EPRI document evaluates the estimated maximum fluence levels and degree of embrittlement that was projected for the high stress (knuckle) region of the BWR reactor vessel supports. Also, the temperatures and loading conditions in the knuckle region were examined to determine whether irradiation induced embrittlement of the reactor vessel support steel could reduce the level of toughness and affect the margins against brittle fracture. The EPRI document concludes that the predicted level of embrittlement is minimal, using the appropriate embrittlement trend curve model for the BWR vessel supports after 80 years of plant operation. The predicted level of embrittlement is minimal since the fluence is low, the operating temperature is high, and the ductility of the skirt knuckle region is high. Therefore, the integrity of the reactor vessel supports is assured, and no additional aging management of reactor vessel supports beyond the current ASME Section XI, Subsection IWF (B.2.3.30) AMP is necessary for aging effects due to irradiation during the MNGP 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 RV support steel to perform its component intended functions through the SPEO.

Biological Shield Structural Steel Evaluation

Similar to the reactor vessel support steel addressed above, the potential effects of irradiation on the steel elements (wide flange columns, liner, and welds) of the biological shield across from the active core height are addressed. However, the conclusions of EPRI 300202099 are not applicable to the MNGP biological shield structural steel as the 72 EFPY fluence (E >1 MeV) across from the active fuel is above the 1 x 10^{17} n/cm^2 threshold for embrittlement of steel. As described above, the biological shield is approximately 26-in thick and consists of 27-in wide flange columns tied together by horizontal wide flange beams and ¼” steel plates. These plates are welded to the column flanges, both inside and outside, thereby forming a double walled shell.

Similar to NUREG-1509, the reduction in fracture toughness assessment of the biological shield structural steel can be based on a transition temperature analysis, wherein a demonstration is made that there is adequate margin between the normal operating temperature and the ductile-to-brittle fracture mode transition temperature (commonly known as the nil-ductility transition (NDT) temperature for end-of-life/license (EOL) conditions) or fracture toughness evaluations. The transition temperature approach is based on the proposition that catastrophic failure by brittle fracture can be avoided by maintaining the normal operating biological shield service temperature above the NDT temperature of the steel. When using the transition temperature to evaluate the biological shield integrity, the NDT temperature at EOL should include the irradiation induced shift.

As described in the original construction specifications and confirmed in the material receipt records, the steel elements of the biological shield wall, consisting of the columns, 1/4-inch thick steel liner plates, and transfer beams, are fabricated from steel conforming to ASTM A36 low carbon steel. The assumed initial (unirradiated) NDT temperature, plus 1.3σ, provided in NUREG-1509 Table 4-1 and Table 4-2 for this carbon-manganese material is 39°F. The original specification did not specify that any additional copper or nickel be incorporated into the ASTM A36 material and there are no chemical measurements for copper or nickel in material receipt records for the MNGP biological shield structural steel made from ASTM A36 low carbon steel.

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 that reference 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 dpa that incorporated the effects of flux and fluence, irradiation temperature, and gamma heating as shown by the upper bound line in Figure 3-1 in NUREG-1509. That model included an upper bound transition temperature shift that was adjusted with zero-degree shift at a dpa of 10^{-5}.

For the purpose of this evaluation of the biological shield structural steel, use of the NUREG-1509 trend curve model for NDT shift versus dpa is conservative since there is little copper in the ASTM A36 materials and because the ratio of low energy neutrons to fast neutrons in the biological shield is much smaller than that used in the test reactor experiments. Fluence calculations were performed to confirm the attenuation effects through the reactor vessel and outward to the biological shield. The bounding fluence (E >0.1 MeV) incident on the inner surface of the biological shield at 72 EFPY was determined to be 6.59×10^{18} n/cm^2. The peak fluence at the biological shield inner diameter for 72 EFPY equates to a displacement per atom = 2.07×10^{-3} dpa.

The potential irradiation induced NDT is a function of the dpa fluence shown in NUREG-1509 Figure 3-1. The dashed upper bound curve is based on the fit to the experimental test data for reactor vessel carbon steel support materials (which did not include ASTM A36 materials) under low temperature, low flux neutron exposure conditions. As a result, the weld materials are similar to the ASTM A36 materials for the purposes of this further evaluation, and the same conclusions are made regarding the potential effects of irradiation induced embrittlement for the weld materials incorporated into the biological shield wall as were made regarding the biological shield wall steel elements.

An evaluation of the steel elements of the MNGP biological shield wall was performed by identifying the region of the shield wall subject to high fluence levels and to NDT temperature plus shift near the range of expected operating temperatures. Stress analysis of the area of interest of the shield wall was performed using finite element analysis. To evaluate the stress levels in the biological shield wall, the entire shield wall structure was modeled in ANSYS, including portions of the liner. Maximum tensile stress in the area of interest (adjacent to the active core region) was determined to be 4.49 ksi, which is less than the 6 ksi set NUREG-1509 where fluence levels and NDT temperature plus shift warrant consideration of tensile stress levels through more-detailed fracture mechanics analysis.

Accordingly, the potential effects of irradiation on the steel elements of the biological shield, including the welding material, are not significant. As a result, the integrity of the biological shield is assured, and no additional aging management of the biological shield structural steel beyond the current Structures Monitoring (B.2.3.33) AMP is necessary for aging effects due to irradiation during the SPEO. As such, there is reasonable assurance that a loss (or reduction) of fracture toughness due to irradiation embrittlement will not affect the ability of the biological shield structural steel to perform its component intended functions through the SPEO.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in Branch Technical Position (BTP) IQMB-1 (Appendix A.2, of this SRP-SLR).

QA provisions applicable to SLR are discussed in Section B.1.3.

3.5.2.2.4 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The OE process and acceptance criteria are described in Section B.1.4.

3.5.2.3 Time-Limited Aging Analysis

The TLAAs identified below are associated with the Containments, Structures and Component Support components:

- Section 4.5, *Containment Liner Plate, Metal Containments, and Penetrations Fatigue*
- Section 4.6.1, *Fatigue of Cranes*

3.5.3 Conclusion

The structural components and commodities subject to AMR have been identified in accordance with the criteria of 10 CFR 54.4. The AMPs selected to manage the effects of aging on structural components and commodities are identified in Section 3.5.2 above.

A description of the AMPs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the SPEO.

Therefore, based on the demonstrations provided in Appendix B, the effects of aging associated with the structural components and commodities will be managed such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the SPEO.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-001	Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all	Cracking and distortion due to increased stress levels from settlement.	XI.S2, "ASME Section XI, Subsection IWL, and/or XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. This Item Number is not applicable to the MNGP Mark I steel containment. The Primary Containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building and supported by the Reactor Building basemat. The Reactor Building basemat is addressed with item 3.5.1-044. Further evaluation is documented in Section 3.5.2.2.1.1.
3.5.1-002	Concrete: foundation; subfoundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundation	XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.1.1)	Not applicable. This Item Number is not applicable to the MNGP Mark I steel containment. Further evaluation is documented in Section 3.5.2.2.1.1.
3.5.1-003	Concrete: dome; wall; basemat; ring girders; buttresses, concrete: containment; wall; basemat, concrete: basemat, concrete fill- in annulus	Reduction of strength and modulus of elasticity due to elevated temperature (>150°F general; >200°F local)	Plant-specific AMP or AMP XI.S2 "ASME Section XI, Subsection IWL," and/or XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.2)	Not applicable. There are no containment concrete components exposed to elevated temperature (>150°F general; >200°F local) in the Primary Containment. Further evaluation is documented in Section 3.5.2.2.1.2.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-004	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	XI.S1, "ASME Section XI, Section IWE," and XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. This item number is applicable only to BWR Mark III containments. The inaccessible areas of the drywell shell and drywell head are addressed in items 3.5.1-035 and 3.5.1-041. Further evaluation is documented in Section 3.5.2.2.1.3.1.
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 corrosion	XI.S1, "ASME Section XI, Subsection IWE" and XI.S4 "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. This item number is applicable only to PWR concrete and steel containments, BWR Mark II containments, and BWR Mark I and Mark III concrete containments. Further evaluation is documented in Section 3.5.2.2.1.3.1.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-006	Steel elements: torus shell	Loss of material due to general, pitting, crevice corrosion	XI.S1, “ASME Section XI, Section IWE,” and XI.S4, “10 CFR Part 50, Appendix J”	Yes (SRP-SLR Section 3.5.2.2.1.3.2)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) program and ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of material of the steel elements of the torus shell and the ECCS suction header. Further evaluation is documented in Section 3.5.2.2.1.3.2.
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	XI.S1, "ASME Section XI, Section IWE"	Yes (SRP-SLR Section 3.5.2.2.1.3.3)	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of material of the steel elements in the downcomers and torus shell and ring girders in the Primary Containment. The Structures Monitoring (B.2.3.33) program will be used to manage loss of material of structural steel associated with the torus internal catwalk support columns and the vent line jet deflectors. A generic note E and a plant-specific note are used. Further evaluation is documented in Section 3.5.2.2.1.3.3.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
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 TLAA"	Yes (SRP-SLR Section 3.5.2.2.1.4)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. This item is applicable only to PWR and BWR prestressed concrete containments. Further evaluation is documented in Section 3.5.2.2.1.4.
3.5.1-009	Metal liner, metal plate, personnel airlock, equipment hatch, control rod drive (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 fatigue	TLAA, SRP-SLR "Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Fatigue is a TLAA for the downcomers, torus penetrations, torus shell, vent header, vent line, and vent line bellow; as well as for drywell penetration bellows (hot pipe penetration bellows) and refueling bellows skirt (the limiting condition for the drywell to reactor building refueling seal and RPV to drywell refueling seal) components. This TLAA is evaluated in Section 4.5. Further evaluation is documented in Section 3.5.2.2.1.5.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-010	Penetration Sleeves; penetration bellows	Cracking due to SCC	XI.S1, "ASME Section XI, Subsection IWE," and XI.S4, "10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.6)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) program and ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage cracking of stainless steel and dissimilar metal welds, as well as Inconel, mechanical bellows. Further evaluation is documented in Section 3.5.2.2.1.6.
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 AMP or XI.S2 "ASME Section XI, Subsection IWL," and/or XI.S6, "Structures Monitoring," enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.7)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. The Primary Containment structure is completely enclosed and sheltered within the air - indoor environment of the Reactor Building. Primary Containment structure internal concrete is not exposed to air - outdoor, or groundwater/soil environments. Further evaluation is documented in Section 3.5.2.2.1.7.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
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 AMP or XI.S2 “ASME Section XI, Subsection IWL,” and/or XI.S6, “Structures Monitoring,” enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.1.8)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. Concrete internal to the Primary Containment and Reactor Building concrete are addressed with item 3.5.1-054. Further evaluation is documented in Section 3.5.2.2.1.8.
3.5.1-013	Item number 3.5.1-013 is deleted 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 AMP or XI.S2 “ASME	Yes (SRP-SLR Section 3.5.2.2.1.9)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. Further evaluation is documented in Section 3.5.2.2.1.9.
3.5.1-015	Item number 3.5.1-015 is deleted in NUREG-2192.				
3.5.1-016	Reinforced concrete containment structure (accessible)	Increase in porosity and permeability Cracking; Loss of material (spalling, scaling) due to aggressive chemical attack	XI.S2, "ASME Section XI, Subsection IWL" and/or XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the MNGP Mark I steel containment on steel members supported by the Reactor Building foundation. The Reactor Building foundation is addressed with item 3.5.1-042.
3.5.1-017	Item number 3.5.1-017 is deleted in NUREG-2192				

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-018	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze- thaw	XI.S2, "ASME Section XI, Section IWL," and/or XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the MNGP Mark I steel containment on steel members supported by the Reactor Building foundation. The Reactor Building foundation is addressed with item 3.5.1-064.
3.5.1-019	Reinforced concrete containment structure (accessible)	Cracking due to expansion from reaction with aggregates	XI.S2, "ASME Section XI, Section IWL," and/or XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the MNGP 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	XI.S2, "ASME Section XI, Section IWL"	No	Not applicable. This item number is not applicable to the MNGP Mark I steel containment.
3.5.1-021	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel	Cracking; loss of bond; loss of material (spalling, scaling) due to corrosion of embedded steel	XI.S2, "ASME Section XI, Subsection IWL" and/or XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the MNGP Mark I steel containment.
3.5.1-022	Item number 3.5.1-022 is deleted 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	XI.S2, "ASME Section XI, Subsection IWL" and/or XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the MNGP Mark I steel containment.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
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	XI.S2, "ASME Section XI, Subsection IWL" and/or XI.S6, "Structures Monitoring"	No	Not applicable. This item number is not applicable to the MNGP Mark I steel containment.
3.5.1-025	Item number 3.5.1-025 is deleted in NUREG-2192.				
3.5.1-026	Moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	XI.S1, "ASME Section XI, Section IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of sealing of the of the drywell moisture barrier in the Primary Containment structure.
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)	XI.S1, "ASME Section XI, Section IWE," and XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191 with exceptions. The 10 CFR Part 50, Appendix J (B.2.3.31) program and ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage cracking of steel high-temperature piping drywell penetrations (adapters) due to cyclic loading Further evaluation is documented in Section 3.5.2.2.1.5.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-028	Personnel airlock, equipment hatch, CRD hatch	Loss of material due to general, pitting, crevice corrosion	XI.S1, “ASME Section XI, Subsection IWE” and XI.S4 “10 CFR Part 50, Appendix J”	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) program and ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of material of the steel personnel airlock, equipment hatch, CRD hatch, and seismic restraint inspection ports.
3.5.1-029	Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms	Loss of leak tightness due to mechanical wear	XI.S1 "ASME Section XI, Subsection IWE" and XI.S4, “10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) program and ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of leak tightness of the steel personnel airlock, equipment hatch, CRD hatch, locks, hinges, and closure mechanisms.
3.5.1-030	Pressure-retaining bolting	Loss of preload due to self-loosening	XI.S1, "ASME Section XI, Section IWE," and XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) program and ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of preload.
3.5.1-031	Pressure-retaining bolting, steel elements: downcomer pipes	Loss of material due to general, pitting, crevice corrosion	XI.S1, "ASME Section XI, Section IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of material.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-032	Prestressing system: tendons; anchorage components	Loss of material due to corrosion	XI.S6, "Structures Monitoring"	No	Not applicable. This item is not applicable to the MNGP Mark I steel containment. This item number is applicable only to PWR and BWR prestressed concrete containments.
3.5.1-033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface, cracks, other defects	XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) program will be used to manage loss of sealing of the elastomer seals and gaskets 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	XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coatings Monitoring and Maintenance (B.2.3.35) program will be used to manage loss of coating or lining integrity of the Service Level I coatings in the Primary Containment.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	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 sand pocket regions; suppression chamber; drywell; embedded shell; region shielded by diaphragm floor (as applicable)	Loss of material due to general, pitting, crevice corrosion	XI.S1, “ASME Section XI, Section IWE,” and XI.S4, “10 CFR Part 50, Appendix J”	Yes (SRP-SLR Section 3.5.2.2.1.3)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) and ASME Section XI, Subsection IWE Section (B.2.3.29) programs will be used to manage loss of material of steel, dissimilar metal welds, electrical penetrations, drywell mechanical penetrations, drywell shell and head, and drywell in the sand pocket region (accessible and inaccessible areas). Further evaluation is documented in Section 3.5.2.2.1.3.
3.5.1-036	Steel elements: drywell head; downcomers	Loss of material due to mechanical wear, including fretting	XI.S1, "ASME Section XI, Section IWE"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage loss of material of the steel downcomers and drywell head.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	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	XI.S1, "ASME Section XI, Section IWE," and XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG-2191. This item number is applicable only to BWR Mark I concrete containments with steel liner plates; however, this material, environment, and aging effect combination is applicable to the MNGP Mark I steel containment. The stainless steel thermowells in treated water will be managed by ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31) programs.
3.5.1-038	Steel elements: suppression chamber shell (interior surface)	Cracking due to SCC	XI.S1, "ASME Section XI, Section IWE," and XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.6)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. This item number is applicable only to BWR Mark III containments. Further evaluation is documented in Section 3.5.2.2.1.6.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-039	Steel elements: vent line bellows	Cracking due to SCC	XI.S1, "ASME Section XI, Section IWE," and XI.S4, "10 CFR Part 50, Appendix J"	Yes (SRP-SLR Section 3.5.2.2.1.6)	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J (B.2.3.31) program and ASME Section XI, Subsection IWE (B.2.3.29) program will be used to manage cracking of the stainless steel vent line bellows. The Structures Monitoring (B.2.3.33) program will be used to manage cracking of the stainless steel RPV to drywell refueling seal bellows assemblies in the Primary Containment. Further evaluation is documented in Section 3.5.2.2.1.6.
3.5.1-040	Unbraced downcomers, steel elements: vent header; downcomers	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	XI.S1, "ASME Section XI, Section IWE"	Yes (SRP-SLR Section 3.5.2.2.1.5)	Not applicable. This item number is not applicable to the MNGP Mark I steel containment. This item number is applicable only to BWR Mark II containments. Further evaluation is documented in Section 3.5.2.2.1.5.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-041	Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt	None	None	No	Consistent with NUREG-2191. This item number has been used for the steel drywell support skirt which is embedded within reinforced concrete and the bottom portion of the drywell exposed to concrete. Steel components contained within concrete do not require an AMP as described in the GALL-SLR report.
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"	Yes (SRP-SLR Section 3.5.2.2.2.1.1)	Group 7 structures are not applicable to MNGP. MNGP is located in a severe weathering region, where freezing conditions are occasionally experienced. However, a plant-specific AMP is not required to manage loss of material, cracking in inaccessible areas. Consistent with the current renewed licenses, the Structures Monitoring (B.2.3.33) AMP would detect degradation of concrete due to freeze-thaw, should it occur, and includes opportunistic examination of normally inaccessible components when excavated for other reasons. Further evaluation is documented in Section 3.5.2.2.2.1, item 1.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
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"	Yes (SRP-SLR Section 3.5.2.2.2.1.2)	Group 7 structures are not applicable to MNGP. Consistent with the current renewed licenses, a plant-specific AMP is not required to manage cracking in inaccessible areas. The Structures Monitoring (B.2.3.33) AMP includes examination for unique “map” or “cracking.” The Structures Monitoring (B.2.3.33) AMP also includes opportunistic examination of below-grade inaccessible concrete areas. Further evaluation is documented in Section 3.5.2.2.2.1, item 2.
3.5.1-044	All Groups: concrete: all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Group 7 structures are not applicable to MNGP. Consistent with NUREG-2191. MNGP does not rely on a dewatering system; thus, the Structures Monitoring (B.2.3.33) AMP will be used to manage cracking and distortion of the reinforced concrete elements of the MNGP structures founded on soil and/or exposed to a soil environment. Further evaluation is documented in Section 3.5.2.2.2.1, item 3.
3.5.1-045	Item number 3.5.1-045 is deleted in NUREG-2192.				

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-046	Groups 1-3, 5-9: concrete: foundation; sub foundation	Reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete sub foundation	AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1.3)	Not applicable. The foundation designs do not incorporate porous concrete in the sub-foundation. Since the magnitude of the total settlements is small, differential settlement distortion is insignificant for MNGP structures. Further evaluation is documented in Section 3.5.2.2.2.1, item 3.
3.5.1-047	Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below- grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation.	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.1.4)	Group 7 and group 8 structures are not applicable to MNGP. The Structures Monitoring (B.2.3.33) AMP will be used to manage increase in porosity and permeability, loss of strength of the reinforced concrete basemat, foundation, sub-foundation, below-grade exterior concrete, pedestal, walls, slabs (inaccessible areas), diesel fuel oil storage tank deadmen, 345 kV house, trenches, and duct bank exposed to water- flowing in Groups 2, 3, and 9 structures. Further evaluation is documented in Section 3.5.2.2.2.1, item 4.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
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"	Yes (SRP-SLR Section 3.5.2.2.2.2)	Not applicable. A plant-specific AMP is not required. Reduction of strength and modulus are not aging effects requiring management at MNGP. There are no concrete structures exposed to elevated temperature (>150°F general; >200°F local) in Structures and Component Supports. Further evaluation is documented in Section 3.5.2.2.2.2.
3.5.1-049	Group 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"	Yes (SRP-SLR Section 3.5.2.2.2.3.1)	MNGP is located in a severe weathering region. The INS (including access tunnel roof slabs) are occasionally exposed to freezing temperatures. The Structures Monitoring (B.2.3.33) AMP will be used to manage loss of material (spalling, scaling) and cracking of the reinforced concrete above-grade exterior (inaccessible areas), basemat, foundation, sub-foundation (inaccessible areas), below-grade exterior (inaccessible areas), and interior (inaccessible areas) exposed to air - outdoor in Group 6 structures. Further evaluation is documented in Section 3.5.2.2.2.3, Item 1.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
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"	Yes (SRP-SLR Section 3.5.2.2.2.3.2)	The Structures Monitoring (B.2.3.33) AMP (which includes opportunistic inspection of inaccessible concrete when excavated for other reasons) is credited with managing cracking in inaccessible areas of MNGP structures. Further evaluation is documented in Section 3.5.2.2.2.3, Item 2.
3.5.1-051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.3.3)	The Structures Monitoring (B.2.3.33) AMP will be used to manage increase in porosity and permeability, loss of strength of the reinforced concrete above-grade exterior (inaccessible areas), basemat, foundation, sub-foundation (inaccessible areas), below-grade exterior (inaccessible areas), and interior (inaccessible areas) exposed to water - flowing in MNGP INS.. Further evaluation is documented in Section 3.5.2.2.2.3, Item 3.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-052	Groups 7, 8 - steel components: tank liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	Plant-specific aging management program or AMP XI.S6, "Structures Monitoring"	Yes (SRP-SLR Section 3.5.2.2.2.4)	Not applicable. There are no Group 7 or Group 8 tanks with liners exposed to water in scope for this application. The Condensate Storage Tank is a steel tank addressed by items 3.4.1-062, 3.4.1-066, and 3.4.1-081. Further evaluation is documented in Section 3.5.2.2.2.4.
3.5.1-053	Support members; welds; bolted connections; support anchorage to building structure	Cumulative fatigue damage due to cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.3 "Metal Fatigue," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses"	Yes (SRP-SLR Section 3.5.2.2.2.5)	Not applicable. There are no support members; welds; bolted connections; or support anchorages to building structure subject to cumulative fatigue damage due to cyclic loading in Structures and Component Supports. Fatigue analysis for cranes and lifting devices items are addressed by item 3.3.1-001. Fatigue analysis for Containment items is addressed by item 3.5.1-009. Further evaluation is documented in Section 3.5.2.2.2.5.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**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. The Structures Monitoring (B.2.3.33) AMP is credited with managing cracking of accessible concrete exposed to uncontrolled indoor air, and outdoor air environments.
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. The Structures Monitoring (B.2.3.33) AMP is credited with managing reduction in concrete anchor capacity for accessible concrete exposed to uncontrolled indoor air, and outdoor air environments.
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. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing loss of material and cavitation of accessible concrete exposed to a water – flowing or standing environment.
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.2.3.30) AMP is credited with managing loss of mechanical function for constrain and variable load supports exposed to an uncontrolled indoor air environment.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**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	Not applicable. Consistent with the current renewed licenses, earthen water control structures, dams, embankments, reservoirs, channels, and ponds are not credited at MNGP.
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. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing cracking, loss of bond, and loss of material (spalling, scaling) of accessible INS concrete exposed to outdoor air.
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. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing loss of material and cracking, loss of bond of accessible INS concrete exposed to outdoor air.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-061	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing an increase in porosity and permeability and loss of strength for accessible INS concrete exposed to outdoor air, and water-flowing or standing.
3.5.1-062	Group 6: Wooden Piles; sheeting	Loss of material; change in material properties due to weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	AMP XI.S7, "Inspection of Water- Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable. There are no wooden piles or sheeting used in MNGP structures or component supports. Steel piles associated with the INS are addressed in item 3.5.1-079 below.
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	Group 7 and Group 8 structures are not applicable to MNGP. Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP is credited with managing leaching or carbonation of exterior plant structure concrete and foundations where groundwater or precipitation run-off forms a flowing water environment.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
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	Group 7 and Group 8 structures are not applicable to MNGP. Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of material and cracking for accessible plant structure concrete exposed to outdoor air.
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	Group 7 and Group 8 structures are not applicable to MNGP. Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP is credited with managing cracking, loss of bond, loss of material for inaccessible plant structure concrete exposed to groundwater/soil.
3.5.1-066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	Cracking, Loss of bond, Loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6 "Structures Monitoring"	No	Group 7 and Group 8 structures are not applicable to MNGP. Consistent with NUREG-2191 The Structures Monitoring (B.2.3.33) AMP is credited with managing cracking, loss of bond, and loss of material for accessible plant structure concrete exposed to uncontrolled indoor air, and outdoor air environments.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**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: below-grade exterior; foundation, Group 6: concrete: all	Increase in porosity and permeability, Cracking, Loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S6 "Structures Monitoring"	No	Group 7 and Group 8 structures are not applicable to MNGP. Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP is credited with managing potential increase in porosity and permeability, cracking, and loss of material due to aggressive chemical attack for inaccessible plant structure concrete in uncontrolled indoor air, outdoor air, and groundwater/soil environments.
3.5.1-068	High-strength steel structural bolting	Cracking due to SCC	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable. There is no high-strength steel structural bolting used in MNGP structures or component supports.
3.5.1-069	Item number 3.5.1-069 is deleted in NUREG-2192.				
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. The Masonry Walls (B.2.3.32) AMP is credited with managing cracking of masonry walls exposed to uncontrolled indoor air and outdoor air.
3.5.1-071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze- thaw	AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Masonry Walls (B.2.3.32) AMP is credited with managing cracking of masonry walls due to freeze-thaw.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
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. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of sealing for seals and weatherproofing in the Diesel Fuel Oil Transfer House, DGB, EFB, Fire Protection Barrier and Commodity Group, HPCI Building, INS, Off Gas Stack, Plant Control and Cable Spreading Structure, Radioactive Waste Building, Reactor Building, Structures Affecting Safety, and Turbine Building.
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.S6, "Structures Monitoring"	No	Not used. Service Level 1 coatings inside Primary Containment (including those on group 4 internal structures) are addressed in item 3.5.1-034 above.
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	Not used. Applicable sliding components addressed under item 3.5.1-075.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
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.2.3.30) AMP will be used to manage the loss of mechanical function of the Lubrite sliding surfaces in the Component Supports commodity group for supports for ASME Class 1 piping and components, ASME Class 2 and 3 piping and components, and for Torus saddles, exposed to air- indoor uncontrolled
3.5.1-076	Sliding surfaces: radial beam seats in BWR drywell	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, "Structures Monitoring"	No	Not used. Sliding surfaces for the radial beam seats that support the platforms and components inside the drywell is addressed in item 3.5.1-075 above.
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. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of material of structural steel components exposed to uncontrolled indoor air and outdoor air.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	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 exception. The Water Chemistry (B.2.3.2) AMP and monitoring of the spent fuel pool water level and leakage from the leak chase channels are credited with managing cracking and loss of material of the stainless-steel spent fuel pool liner exposed to treated water.
3.5.1-079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of material of steel plates and piles in the HPCI building, INS, and Underground Duct Bank.
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. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of material for structural bolting exposed to uncontrolled indoor air and outdoor air.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**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.2.3.30) AMP will be used to manage loss of material of the carbon and low alloy steel structural bolting in supports for ASME Class 1 piping and components: constant and variable load spring hangers; guides; stops, supports for ASME Class 1 piping and components: support members; welds; bolted connections; support anchorage to building structure, supports for ASME Class 2 and 3 piping and components: constant and variable load spring hangers; guides; stops, supports for ASME Class 2 and 3 piping and components: support members; welds; bolted connections; support anchorage to building structure, supports for ASME Class MC components: constant and variable load spring hangers; guides; stops, and supports for ASME Class MC components: support members; welds; bolted connections; support anchorage to building structure exposed to air - indoor uncontrolled and air - outdoor in the Component Supports commodity group.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of material for structural bolting exposed to uncontrolled indoor air and outdoor air.
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. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing loss of material for structural bolting exposed to outdoor air and water – flowing or standing in the INS.
3.5.1-084	Item 3.5.1-084 is deleted in NUREG-2192.				
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 exception for Water Chemistry (B.2.3.2). The Water Chemistry (B.2.3.2) AMP and ASME Section XI, Subsection IWF (B.2.3.30) AMP are credited with managing loss of material for stainless bolting exposed to treated water in the spent fuel pool.
3.5.1-086	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.S3, "ASME Section XI, Section IWF"	No	Not applicable. There are no ASME Class 1, 2, or MC Structural Bolts in an air – outdoor environment.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
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.2.3.30) AMP is credited with managing loss of preload for structural bolting for ASME Class 1, 2, 3, and MC supports.
3.5.1-088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191 with exception. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of preload for structural bolting exposed to uncontrolled indoor air and outdoor air.
3.5.1-089	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to boric acid corrosion	AMP XI.M10, "Boric Acid Corrosion"	No	Not applicable. Item number 3.5.1-089 is applicable to PWRs only and is not used for MNGP.
3.5.1-090	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Not used. Stainless steel bolting exposed to treated water in the spent fuel pool is addressed in item number 3.5.1-085.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	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.2.3.30) AMP is credited with managing loss of material for ASME Class 1, 2, 3, and MC support members, welds, bolted connections, and support anchorage.
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. The Structures Monitoring (B.2.3.33) AMP will be used to manage loss of material for support members, welds, bolted connections, and support anchorage exposed to uncontrolled indoor air and outdoor air environments.
3.5.1-093	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting, crevice corrosion	AMP XI.S6, "Structures Monitoring"	No	Not used. Galvanized steel support members, bolted connections, and support anchorage to building structure are credited to item number 3.5.1-082 and item number 3.5.1-077.
3.5.1-094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, "ASME Section XI, Subsection IWF," and/or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF (B.2.3.30) AMP and Structures Monitoring (B.2.3.33) AMP are credited with managing vibration isolation elements for pertinent component supports.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports					
Item Number	**Component**	**Aging Effect Requiring Management**	**Aging Management Program**	**Further Evaluation Recommended**	**Discussion**
3.5.1-095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not used. Galvanized steel support members, bolted connections, and support anchorage to building structure are credited to item number 3.5.1-082 and item number 3.5.1-077.
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. The Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34) AMP is credited with managing cracking for accessible INS concrete.
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 other selected AMPs, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.6)	Consistent with NUREG-2191 (as supplemented by SLR-ISG-2021-03-STRUCTURES). Further evaluation is documented in Section 3.5.2.2.2.6.
3.5.1-098	Stainless steel, aluminum alloy support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not used. This component, material, and environment combination is addressed by item number 3.5.1-099.

Table 3.5-1: Summary of Aging Management Evaluations for Plant Structures and Component Supports

Item Number	Component	Aging Effect Requiring Management	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-099	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion, cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.S3, "ASME Section XI, Subsection IWF," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191. The One-Time Inspection (B.2.3.20) AMP will be used to manage cracking and loss of material of the fuel prep machine framing. The ASME Section XI, Subsection IWF (B.2.3.30) AMP will be used to manage loss of material of ASME Class 1, 2, 3, and MC supports. See Section 3.5.2.2.2.4.
3.5.1-100	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion, cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.S6, "Structures Monitoring," or AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191, as clarified. The Structures Monitoring (B.2.3.33) AMP is credited with managing loss of material and cracking of aluminum and stainless steel electrical enclosures, aluminum platform components, aluminum fuel storage racks (new fuel), stainless steel cap, and other miscellaneous stainless steel structural components exposed to air. The External Surfaces Monitoring of Mechanical Components (B.2.3.23) AMP is credited with managing loss of material and cracking of aluminum and stainless steel insulation jacketing. Further evaluation is documented in Section 3.5.2.2.2.4.

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Biological Shield Wall	Radiation Shielding Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking, Loss of Bond, Loss of Material	Structures Monitoring (B.2.3.33)	III.A4.TP-26	3.5.1-066	A, 6, 7
Biological Shield Wall	Radiation Shielding	Concrete (Reinforced)	Air – Indoor Uncontrolled	Reduction of Strength, Loss of Mechanical Properties	Structures Monitoring (B.2.3.33)	III.A4.T-35	3.5.1-097	A, 6, 7
Biological Shield Wall (Accessible Areas)	Radiation Shielding Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A4.TP-25	3.5.1-054	A, 6, 7
Biological Shield Wall (Columns, Beams, Liner, Doors)	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A4.TP-302	3.5.1-077	C, 6
Biological Shield Wall (Inaccessible Areas)	Radiation Shielding Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A4.TP-204	3.5.1-043	A, 1, 6
Bolting (Containment Closure)	Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B4.CP-148	3.5.1-031	B
Bolting (Containment Closure)	Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-150	3.5.1-030	B
Bolting (Structural)	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A4.TP-248	3.5.1-080	A
Bolting (Structural)	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A4.TP-261	3.5.1-088	A
Concrete: Interior (Drywell Equipment Foundation, RPV Pedestal)	Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Reduction of Strength, Loss of Mechanical Properties	Structures Monitoring (B.2.3.33)	III.A4.T-35	3.5.1-097	A, 1

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Interior (Drywell Equipment Foundation, RPV Pedestal) (Accessible Areas)	Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A4.TP-25	3.5.1-054	A
Concrete: Interior (Drywell Equipment Foundation, RPV Pedestal) (Accessible Areas)	Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking, Loss of Bond, Loss of Material	Structures Monitoring (B.2.3.33)	III.A4.TP-26	3.5.1-066	A
Concrete: Interior (Drywell Equipment Foundation, RPV Pedestal) (Inaccessible Areas)	Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	III.A4.TP-204	3.5.1-043	A, 1
Downcomers	Direct Flow Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA – Section 4.5, Containment Liner Plate, Metal Containments and Penetrations Fatigue	II.B1.1.C-21	3.5.1-009	A
Downcomers	Direct Flow Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B1.1.C-23	3.5.1-036	B
Downcomers	Direct Flow Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B1.1.CP-109	3.5.1-007	B
Downcomers	Direct Flow Pressure Boundary Structural Support	Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B1.1.CP-109	3.5.1-007	B

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Drywell Shell; Drywell Head; Drywell Shell In Sand Pocket Regions (Accessible)	HELB Barrier Missile Barrier Pressure Boundary Shelter/Protection Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B1.1.CP-43	3.5.1-035	B
Drywell Shell; Drywell Head; Drywell Shell In Sand Pocket Regions (Inaccessible)	HELB Barrier Missile Barrier Pressure Boundary Shelter/Protection Structural Support	Steel	Air – Indoor Uncontrolled; Concrete	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B3.1.CP-113	3.5.1-004	D, 9
Drywell Support Skirt, Embedded Shell	Structural Support	Steel	Concrete	None	None	II.B1.1.CP-44	3.5.1-041	A
ECCS Suction Header	Emergency Cooling Water Source Pressure Boundary	Steel	Air – Indoor Uncontrolled, Treated Water	Cumulative Fatigue Damage	TLAA – Section 4.5, Containment Liner Plate, Metal Containments and Penetrations Fatigue	II.B1.1.C-21	3.5.1-009	A, 8
ECCS Suction Header	Emergency Cooling Water Source Pressure Boundary	Steel	Air – Indoor Uncontrolled, Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B1.1.CP-48	3.5.1-006	D, 8
Liner, Liner Anchors, Integral Attachments - (RPV Pedestal)	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A4.TP-302	3.5.1-077	C
Moisture Barrier	Shelter/Protection	Elastomer, Rubber and Other Similar Materials	Air – Indoor Uncontrolled	Loss of Sealing	ASME Section XI, Subsection IWE (B.2.3.29)	II.B4.CP-40	3.5.1-026	B

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Penetration Assemblies - Electrical	Flood Barrier HELB Barrier Pressure Boundary Shelter/Protection Structural Support	Stainless Steel; Dissimilar Metal Welds	Air – Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-38	3.5.1-010	B
Penetration Assemblies - Electrical	Flood Barrier HELB Barrier Pressure Boundary Shelter/Protection Structural Support	Steel; Dissimilar Metal Welds	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-36	3.5.1-035	B
Penetration Assemblies - Mechanical (Bellows)	Flood Barrier HELB Barrier Pressure Boundary Structural Support	Inconel, Dissimilar Metal Welds	Air – Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-38	3.5.1-010	B, 2
Penetration Assemblies - Mechanical (Bellows)	Flood Barrier HELB Barrier Pressure Boundary Shelter/Protection Structural Support	Stainless Steel; Dissimilar Metal Welds	Air – Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-38	3.5.1-010	B
Penetration Assemblies - Mechanical (Sleeves)	Flood Barrier HELB Barrier Pressure Boundary Shelter/Protection Structural Support	Steel; Dissimilar Metal Welds	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-36	3.5.1-035	B
Penetration Assemblies - Mechanical Piping (Adapters)	Flood Barrier HELB Barrier Pressure Boundary Shelter/Protection Structural Support	Steel; Stainless Steel; Dissimilar Metal Welds	Air – Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-37	3.5.1-027	B, 11

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Penetration Assemblies - Mechanical Piping (Torus Penetrations, Drywell Penetration Bellows)	Flood Barrier HELB Barrier Pressure Boundary Shelter/Protection Structural Support	Steel; Stainless Steel; Dissimilar Metal Welds	Air – Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA – Section 4.5, Containment Liner Plate, Metal Containments and Penetrations Fatigue	II.B4.C-13	3.5.1-009	A
Personnel Airlock, Equipment Hatch, CRD Hatch, Seismic Restraint Inspection Ports, Including Locks, Hinges, and Closure Mechanisms	Flood Barrier Helb Barrier Missile Barrier Pressure Boundary	Steel	Air – Indoor Uncontrolled	Loss of Leak Tightness	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-39	3.5.1-029	B
Personnel Airlock, Equipment Hatch, CRD Hatch, Seismic Restraint Inspection Ports, Including Locks, Hinges, and Closure Mechanisms	Flood Barrier Helb Barrier Missile Barrier Pressure Boundary	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.C-16	3.5.1-028	B
RPV to Drywell Refueling Seal	Structural Support Watertight Seal	Stainless Steel	Air – Indoor Uncontrolled	Cracking	Structures Monitoring (B.2.3.33)	II.B1.1.CP-50	3.5.1-039	E, 3
RPV to Drywell Refueling Seal (Refueling Bellows Skirt)	Structural Support Watertight Seal	Stainless Steel	Air – Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA – Section 4.5, Containment Liner Plate, Metal Containments and Penetrations Fatigue	II.B1.1.C-21	3.5.1-009	C
Seals and Gaskets	Helb Barrier Pressure Boundary	Elastomer, Rubber And Other Similar Materials	Air – Indoor Uncontrolled	Loss of Sealing	10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-41	3.5.1-033	A

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Service Level I Coatings	Maintain Adhesion	Coatings	Air – Indoor Uncontrolled, Treated Water	Loss of Coating or Lining Integrity	Protective Coating Monitoring and Maintenance (B.2.3.35)	II.B4.CP-152	3.5.1-034	A
Sliding Surfaces (Drywell Interior Platform Sliding Plates)	Structural Support	Lubrite®	Air – Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-45	3.5.1-075	A, 10
Structural Steel (Torus Internal Catwalk Support Columns)	Structural Support	Steel	Treated Water	Loss of Material	Structures Monitoring (B.2.3.33)	II.B1.1.CP-109	3.5.1-007	E,4
Structural Steel (Torus Internal And External Catwalks, Drywell Interior Platforms, Stabilizers, Radial Beam Seats, etc.)	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A4.TP-302	3.5.1-077	A
Thermowells	Flood Barrier Pressure Boundary Structural Support	Stainless Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29), 10 CFR Part 50, Appendix J (B.2.3.31), and Water Chemistry (B.2.3.2)	II.B2.2.C-49	3.5.1-037	D, 5
Torus Shell	Emergency Cooling Water Source Flood Barrier Heat Sink HELB Barrier Missile Barrier Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled, Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B1.1.CP-48	3.5.1-006	B

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Torus Shell, Ring Girders	Emergency Cooling Water Source Flood Barrier Heat Sink HELB Barrier Missile Barrier Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled, Treated Water	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B1.1.CP-109	3.5.1-007	B
Torus, Vent Lines, Vent Header	Emergency Cooling Water Source Direct Flow Flood Barrier Heat Sink HELB Barrier Missile Barrier Pressure Boundary Structural Support	Steel	Air – Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA – Section 4.5, Containment Liner Plate, Metal Containments and Penetrations Fatigue	II.B1.1.C-21	3.5.1-009	A
Vent Line Bellows	Flood Barrier Pressure Boundary Structural Support	Dissimilar Metal Welds	Air – Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B4.CP-38	3.5.1-010	B
Vent Line Bellows	Flood Barrier Pressure Boundary Structural Support	Stainless Steel	Air – Indoor Uncontrolled	Cracking	ASME Section XI, Subsection IWE (B.2.3.29) and 10 CFR Part 50, Appendix J (B.2.3.31)	II.B1.1.CP-50	3.5.1-039	B

Table 3.5.2-1: Primary Containment – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Vent Line Bellows	Flood Barrier Pressure Boundary Structural Support	Stainless Steel	Air – Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA – Section 4.5, Containment Liner Plate, Metal Containments and Penetrations Fatigue	II.B1.1.C-21	3.5.1-009	A
Vent Line Jet Deflectors	Shelter/Protection HELB Barrier	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWE (B.2.3.29)	II.B1.1.CP-109	3.5.1-007	B

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant-Specific Notes

1. Consistent with SLR-ISG-2021-03-STRUCTURES, which allows the Structures Monitoring (B.2.3.33) AMP to manage the effects of aging in the place of a plant-specific AMP.

2. Drywell penetration X-16B bellows are constructed of Inconel. Inconel is very similar to stainless steel and is subject to the same aging effects.

3. The RPV to drywell refueling seal will be managed by the Structures Monitoring (B.2.3.33) AMP instead of ASME Section XI, Subsection IWE (B.2.3.29) AMP; as it is not a pressure retaining component.

4. Structural steel in treated water will be managed by the Structures Monitoring (B.2.3.33) AMP; as it is not a pressure retaining component.

5. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item associated with Mark II containments. MNGP is a Mark I containment.

6. As described in USAR 12.2.2.1.1, the concrete of the biological shield, above the 959-ft elevation, provides a shielding intended function. Above the 959-ft elevation, the liners and internal columns provide adequate structural support.

7. Consistent with SLR-ISG-2021-03-STRUCTURES, which allows a plant-specific AMP, or a selected AMP enhanced as necessary; the Structures Monitoring (B.2.3.33) AMP will be used to manage the potential for reduction in strength, loss of mechanical properties, or cracking of the biological shield due to irradiation near the reactor vessel, as the projected values for neutron and gamma radiation incident on the shield wall are less than the threshold values of $1x10^{19}$ n/cm^2 and $1x10^{10}$ rads, respectively.

8. The Emergency Core Cooling System (ECCS) ring header is considered part of primary containment because there is no isolation between the torus and the ECCS ring header.

9. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item associated with Mark III containments. MNGP is a Mark I containment.

10. Lubrite plates did not have an applicable aging effect or AMP in NUREG-1801 or for MNGP initial LR.

11. High-temperature piping penetrations, such as for main steam and feedwater, are considered susceptible to cyclic loading.

Table 3.5.2-2: Cranes, Heavy Loads – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Cranes and Lifting Devices	Structural Support	Steel	Air – Indoor Uncontrolled	Cumulative Fatigue Damage	TLAA – Section 4.6.1, Fatigue of Cranes (Crane Cycle Limits)	VII.B.A-06	3.3.1-001	A
Cranes and Lifting Devices	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-07	3.3.1-052	A
Fuel Prep Machine Framing	Structural Support	Aluminum	Air – Indoor Uncontrolled	Cracking Loss of Material	One-Time Inspection (B.2.3.20)	III.B1.1.T-36a	3.5.1-099	A
Fuel Prep Machine Framing	Structural Support	Aluminum	Treated Water	Loss of Material	Water Chemistry (B.2.3.2) and One-Time Inspection (B.2.3.20)	VII.A4.AP-130	3.3.1-025	D
Refueling Platform	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-07	3.3.1-052	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Cracking Loss of Material Loss of Preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.3.13)	VII.B.A-730	3.3.1-199	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.5.2-3: Diesel Fuel Oil Transfer House – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1

Table 3.5.2-3: Diesel Fuel Oil Transfer House – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1

Table 3.5.2-3: Diesel Fuel Oil Transfer House – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Interior Walls, Ceilings, and Roof	Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Doors	Flood Barrier Shelter, Protection	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Miscellaneous Structural Components	Missile Barrier Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-4: Emergency Diesel Generator Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A

Table 3.5.2-4: Emergency Diesel Generator Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Interior Walls, Ceiling, and Floor	Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A

Table 3.5.2-4: Emergency Diesel Generator Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Doors	Shelter, Protection	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Joint and Penetration Seals	Shelter, Protection	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Joint and Penetration Seals	Flood Barrier	Grout	Air – Indoor Uncontrolled Air – Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.3.33)	III.B2.TP-42	3.5.1-055	A
Masonry (Block) Walls	Flood Barrier Shelter, Protection Structural Support	Concrete Block	Air – Indoor Uncontrolled	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5.1-070	A
Miscellaneous Structural Components	Missile Barrier Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-5: Emergency Filtration Train Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A

Table 3.5.2-5: Emergency Filtration Train Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1

Table 3.5.2-5: Emergency Filtration Train Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Interior Walls, Ceilings, and Roof	Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Doors	Shelter, Protection	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Joint and Penetration Seals	Shelter, Protection	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Miscellaneous Structural Components	Missile Barrier Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-6: Fire Protection Barriers Commodity Group – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Cable Tray Cover	Fire Barrier	Aluminum	Air – Indoor Uncontrolled	None	None	VI.A.L-09	3.6.1-027	A
Fire Barrier Penetration Seals	Fire Barrier	Elastomer	Air – Indoor Uncontrolled	Hardening Loss of Strength Shrinkage	Fire Protection (B.2.3.15)	VII.G.A-19	3.3.1-057	A
Fire Damper Housing	Fire Barrier	Steel	Air – Indoor Uncontrolled	Loss of Material	Fire Protection (B.2.3.15)	VII.G.A-789	3.3.1-255	A
Fire Rated Doors	Fire Barrier	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Fire Protection (B.2.3.15)	VII.G.A-21	3.3.1-059	A
Fireproofing	Fire Barrier	Cementitious	Air – Indoor Uncontrolled	Cracking Change in Material Properties Delamination	Fire Protection (B.2.3.15)	VII.G.A-806	3.3.1-268	A
Fireproofing	Fire Barrier	Cementitious	Air – Indoor Uncontrolled	Loss of Material	Fire Protection (B.2.3.15)	VII.G.A-806	3.3.1-268	A
Masonry (Block) Walls	Fire Barrier	Concrete Block	Air – Indoor Uncontrolled	Cracking Loss of Material	Fire Protection (B.2.3.15) Masonry Walls (B.2.3.32)	VII.G.A-626	3.3.1-179	A
Non-Metallic Fireproofing	Fire Barrier	Cementitious	Air – Indoor Uncontrolled	Cracking Loss of Material Change in Material Properties Delamination	Fire Protection (B.2.3.15)	VII.G.A-806	3.3.1-268	A
Structural Fire Barriers (Walls, Ceilings and Floors)	Fire Barrier	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Material	Fire Protection (B.2.3.15) Structures Monitoring (B.2.3.33)	VII.G.A-90	3.3.1-060	A
Thermal Fiber	Fire Barrier	Silicate	Air – Indoor Uncontrolled	Change in Material Properties	Fire Protection (B.2.3.15)	VII.G.A.-807	3.3.1-269	A

Table 3.5.2-6: Fire Protection Barriers Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Thermal Fiber	Fire Barrier	Silicate	Air – Indoor Uncontrolled	Loss of Material	Fire Protection (B.2.3.15)	VII.G.A.-807	3.3.1-269	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

None.

Table 3.5.2-7: Hangers and Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Anchorage / Embedment	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B3.TP-43	3.5.1-092	A
Anchorage / Embedment	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Anchorage / Embedment	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B3.TP-248	3.5.1-080	A
ASME Class 1 Supports	Structural Support	Stainless Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.T-36b	3.5.1-099	A
ASME Class 1 Supports	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.T-24	3.5.1-091	A
ASME Class 1 Supports	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.T-28	3.5.1-057	A
ASME Class 1 Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-226	3.5.1-081	A
ASME Class 1 Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-229	3.5.1-087	A
ASME Class 2 and 3 Supports	Structural Support	Stainless Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.T-36b	3.5.1-099	A
ASME Class 2 and 3 Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-226	3.5.1-081	A
ASME Class 2 and 3 Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-229	3.5.1-087	A

Table 3.5.2-7: Hangers and Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
ASME Class 2 and 3 Supports	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.T-24	3.5.1-091	A
ASME Class 2 and 3 Supports	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.T-28	3.5.1-057	A
ASME Class MC Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.3.TP-226	3.5.1-081	A
ASME Class MC Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Preload	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.3.TP-229	3.5.1-087	A
ASME Class MC Supports	Structural Support	Stainless Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.3.T-36b	3.5.1-099	A
ASME Class MC Supports	Structural Support	Stainless Steel	Treated Water	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30) and Water Chemistry (B.2.3.2)	III.B1.3.TP-232	3.5.1-085	A
ASME Class MC Supports	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.3.T-24	3.5.1-091	A
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.3.33)	III.B2.TP-42	3.5.1-055	A,2

Table 3.5.2-7: Hangers and Supports Commodity Group – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support	Concrete (Reinforced)	Air – Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.3.33)	III.B2.TP-42	3.5.1-055	A,2
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support	Grout	Air – Indoor Uncontrolled	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.3.33)	III.B2.TP-42	3.5.1-055	A,2
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support	Grout	Air – Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.3.33)	III.B2.TP-42	3.5.1-055	A,2
Component Supports	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B2.TP-43	3.5.1-092	A
Concrete: Diesel Fuel Oil Storage Tank Deadmen	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Diesel Fuel Oil Storage Tank Deadmen	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A
Concrete: Diesel Fuel Oil Storage Tank Deadmen	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A

Table 3.5.2-7: Hangers and Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Diesel Fuel Oil Storage Tank Deadmen	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: Diesel Fuel Oil Storage Tank Deadmen	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Electrical Enclosures	Shelter, Protection Structural Support	Aluminum	Air - Indoor Uncontrolled	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5.1-100	A
Electrical Enclosures	Shelter, Protection Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B2.TP-43	3.5.1-092	A
Electrical Enclosures	Structural Support	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Surface cracking Crazing Scuffing Dimensional change Shrinkage Discoloration Hardening Loss of Strength	Structures Monitoring (B.2.3.33)	VI.A.LP-29	3.6.1-011	E, 1
Electrical Enclosures	Structural Support	Fiberglass	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	VII.I.A-720	3.3.1-150	E, 1
Electrical Enclosures	Structural Support	Stainless Steel	Air - Indoor Uncontrolled	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.B3.T-37b	3.5.1-100	A
HVAC Duct Supports	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A

Table 3.5.2-7: Hangers and Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Insulation	Insulation Jacket Integrity	Aluminum	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	III.B2.T-37c	3.5.1-100	C
Insulation	Insulation Jacket Integrity	Stainless Steel	Air – Indoor Uncontrolled	Cracking Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	III.B2.T-37c	3.5.1-100	C
Insulation	Thermal Insulation	Fiberglass	Air – Indoor Uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B.2.3.23)	V.E.E-422	3.2.1-087	C,3
Pipe Restraints	Pipe Whip Restraint Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A
Sliding Surfaces For ASME Class 1 Piping and Components	Structural Support	Lubrite®	Air – Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.1.TP-45	3.5.1-075	A
Sliding Surfaces For ASME Class 2 and 3 Piping And Components	Structural Support	Lubrite®	Air – Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.TP-45	3.5.1-075	A
Sliding Surfaces For Torus Saddles	Structural Support	Lubrite®	Air – Indoor Uncontrolled	Loss of Mechanical Function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.3.TP-45	3.5.1-075	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B3.TP-248	3.5.1-080	A

Table 3.5.2-7: Hangers and Supports Commodity Group – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.B3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A
Vibration Isolation Elements	Structural Support	Elastomer	Air – Indoor Uncontrolled	Reduction or Loss of Isolation Function	ASME Section XI, Subsection IWF (B.2.3.30)	III.B1.2.T-33	3.5.1-094	A
Vibration Isolation Elements	Structural Support	Elastomer	Air – Indoor Uncontrolled	Reduction or Loss of Isolation Function	Structures Monitoring (B.2.3.33)	III.B4.T-44	3.5.1-094	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

E. Consistent with NUREG-2191 item for material, environment, and aging effect, but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Plant Specific Notes

1. Groundwater is considered to be water-flowing

2. The component type “Building concrete at locations of expansion and grouted anchors; grout pads for support base plates” includes anchorage of racks, panels, cabinets, and enclosures for electrical equipment and instrumentation; building concrete, grout pads.

3. Thermal insulation of reactor coolant and main steam piping that penetrates the biological shield wall ensures local concrete temperatures do not exceed limits. This piping is jacketed, and jacket condition is indicative of insulation condition.

Table 3.5.2-8: High Pressure Coolant Injection Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A

Table 3.5.2-8: High Pressure Coolant Injection Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Radiation Shielding Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Radiation Shielding Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A

Table 3.5.2-8: High Pressure Coolant Injection Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Radiation Shielding Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Radiation Shielding Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Pressure Boundary Radiation Shielding Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A

Table 3.5.2-8: High Pressure Coolant Injection Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Pressure Boundary Radiation Shielding Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Interior Walls, Ceilings, and Roof	Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Joint and Penetration Seals	Shelter, Protection	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Piping Penetration Seal Plates	Flood Barrier Pressure Boundary Shelter, Protection	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Piping Penetration Seal Plates	Flood Barrier Pressure Boundary Shelter, Protection	Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5.1-079	C
Platforms	Structural Support	Aluminum	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5.1-100	A

Table 3.5.2-8: High Pressure Coolant Injection Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-9: Intake Structures – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Bin Wall and Steel Plates	Flood Barrier	Steel	Air-Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Bin Wall and Steel Plates	Flood Barrier	Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5.1-079	A
Concrete: Basemat, Foundation (Accessible)	Flood Barrier Structural Support	Concrete (Reinforced)	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.T-20	3.5.1-056	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Flood Barrier Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A6.TP-220	3.5.1-050	A
Concrete: Basemat, Foundation (Inaccessible)	Flood Barrier Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A6.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Flood Barrier Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A6.TP-107	3.5.1-067	A
Concrete: Basemat, Foundation (Inaccessible)	Flood Barrier Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A6.TP-104	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Flood Barrier Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A6.TP-110	3.5.1-049	A

Table 3.5.2-9: Intake Structures – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor Water - Flowing	Cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-34	3.5.1-096	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor Water - Flowing	Cracking Loss of Bond Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-38	3.5.1-059	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor Water - Flowing	Cracking Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-36	3.5.1-060	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-37	3.5.1-061	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A

Table 3.5.2-9: Intake Structures – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A

Table 3.5.2-9: Intake Structures – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Intake Structure and Access Tunnel Roof Slabs (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-20	3.5.1-056	A, 1
Concrete: Intake Structure and Access Tunnel Roof Slabs (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A6.TP-110	3.5.1-049	A
Concrete: Intake Structure and Access Tunnel Roof Slabs (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A6.TP-109	3.5.1-051	A, 1
Doors, Ventilation Assemblies	Flood Barrier HELB Barrier Shelter, Protection Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Joint and Penetration Seals	Flood Barrier HELB Barrier	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Masonry (Block) Walls	Structural Support	Concrete Block	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A6.T-12	3.5.1-070	A
Masonry (Block) Walls	Structural Support	Concrete Block	Air – Outdoor	Cracking Loss of Material	Masonry Walls (B.2.3.32)	III.A6.TP-34	3.5.1-071	A

Table 3.5.2-9: Intake Structures – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B5.TP-43	3.5.1-092	A
Miscellaneous Structural Components	Flood Barrier Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Sheet Piles	Structural Support	Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5.1-079	A
Stored Steel Plates, Hatch Covers and Bin Wall	Flood Barrier	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)	III.A6.TP-221	3.5.1-083	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A6.TP-261	3.5.1-088	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-10: Miscellaneous Station Blackout Yard Structures – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability; Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Inaccessible)	Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Inaccessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Increase in Porosity and Permeability; Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A

Table 3.5.2-10: Miscellaneous Station Blackout Yard Structures – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Increase in Porosity and Permeability; Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A
Concrete: 345 kV House, Foundations, Trenches, Duct Bank (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Masonry (Block) Walls	Structural Support	Concrete Block	Air – Outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5.1-070	A
Masonry (Block) Walls	Structural Support	Concrete Block	Air – Outdoor	Cracking Loss of Material	Masonry Walls (B.2.3.32)	III.A3.TP-34	3.5.1-071	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B5.TP-43	3.5.1-092	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-11: Off-Gas Stack – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Pedestal, Walls, Slabs (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A9.TP-25	3.5.1-054	A
Concrete: Pedestal, Walls, Slabs (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A9.TP-26	3.5.1-066	A
Concrete: Pedestal, Walls, Slabs (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A9.TP-23	3.5.1-064	A
Concrete: Pedestal, Walls, Slabs (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A9.TP-30	3.5.1-044	A
Concrete: Pedestal, Walls, Slabs (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in porosity and permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A9.TP-24	3.5.1-063	A, 1
Concrete: Pedestal, Walls, Slabs (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A9.TP-204	3.5.1-043	A
Concrete: Pedestal, Walls, Slabs (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A9.TP-28	3.5.1-067	A
Concrete: Pedestal, Walls, Slabs (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A9.TP-29	3.5.1-067	A

Table 3.5.2-11: Off-Gas Stack – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Pedestal, Walls, Slabs (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A9.TP-212	3.5.1-065	A
Concrete: Pedestal, Walls, Slabs (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A9.TP-108	3.5.1-042	A
Concrete: Pedestal, Walls, Slabs (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A9.TP-67	3.5.1-047	A, 1
Doors	Flood Barrier Shelter, Protection	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A,
Masonry (Block) Walls	Shielding Structural Support	Concrete Block	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5.1-070	A
Miscellaneous Structural Components	Flood Barrier Shelter, Protection Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A
Stainless Steel Cap	Shelter, Protection Structural Support	Stainless Steel	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5.1-100	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A9.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

Table 3.5.2-11: Off-Gas Stack – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A9.TP-261	3.5.1-088	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-12: Off-Gas Storage and Compressor Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A

Table 3.5.2-12: Off-Gas Storage and Compressor Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A

Table 3.5.2-12: Off-Gas Storage and Compressor Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-219 1 Item**	**Table 1 Item**	**Notes**
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Interior Walls, Ceilings, and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Doors	Flood Barrier Shelter, Protection	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A,
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water- flowing.

Table 3.5.2-13: Plant Control and Cable Spreading Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A

Table 3.5.2-13: Plant Control and Cable Spreading Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A

Table 3.5.2-13: Plant Control and Cable Spreading Structure – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A

Table 3.5.2-13: Plant Control and Cable Spreading Structure – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Interior Walls, Ceilings, and Roof	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Control Room Seals	Pressure Boundary Flood Barrier	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Masonry (Block) Walls	Flood Barrier Structural Support	Concrete Block	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A1.T-12	3.5.1-070	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-14: Radioactive Waste Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Airlock and Railroad Doors	HELB Barrier Pressure Boundary Shelter, Protection	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A

Table 3.5.2-14: Radioactive Waste Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A

Table 3.5.2-14: Radioactive Waste Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Interior Walls, Ceilings, and Roof	Flood Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Masonry (Block) Walls	Flood Barrier Structural Support	Concrete Block	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A1.T-12	3.5.1-070	A

Table 3.5.2-14: Radioactive Waste Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Railroad Bay Door View Port	Pressure Boundary	Glass	Air – Indoor Uncontrolled Air – Outdoor	None	None	VII.J.AP-48	3.3.1-117	C
Roofing Railroad Bay	Pressure Boundary Shelter, Protection	Elastomer	Air - Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Secondary Containment Seals	Shelter, Protection	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-15: Reactor Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A2.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A2.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-29	3.5.1-067	A

Table 3.5.2-15: Reactor Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A2.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-26	3.5.1-066	A

Table 3.5.2-15: Reactor Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A2.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A2.TP-204	3.5.1-043	A

Table 3.5.2-15: Reactor Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier HELB Barrier Missile Barrier Pressure Boundary Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-28	3.5.1-067	A
Concrete: Interior Walls, Ceilings, and Roof	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-28	3.5.1-067	A
Doors and Frames	Flood Barrier HELB Barrier Pressure Boundary Shelter, Protection	Glass	Air – Indoor Uncontrolled Air – Outdoor	None	None	VII.J.AP-48	3.3.1-117	C
Doors and Frames	Flood Barrier HELB Barrier Pressure Boundary Shelter, Protection	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-302	3.5.1-077	A
Fuel Storage Racks (New Fuel)	Structural Support	Aluminum	Air - Indoor Uncontrolled	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5.1-100	A

Table 3.5.2-15: Reactor Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Fuel Storage Racks: Neutron Absorbing Sheets	Absorb Neutrons	Boral	Treated Water	Change in dimensions Loss of Material Reduction of neutron-absorbing capacity	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.3.26)	VII.A2.AP-236	3.3.1-102	A
Spent Fuel Pool Liner, Dryer / Separator Storage Pool Liner, Reactor Well Liner	Pressure Boundary Structural Support	Stainless Steel	Treated Water	Cracking Loss of Material	Water Chemistry (B.2.3.2) and monitoring of the spent fuel pool water level and leakage from the leak chase channels	III.A5.T-14	3.5.1-078	B
Masonry (Block) Walls	Flood Barrier HELB Barrier Structural Support	Concrete Block	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A1.T-12	3.5.1-070	A
Miscellaneous Structural Components	Flood Barrier Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-302	3.5.1-077	A
Miscellaneous Structural Components	Structural Support	Stainless Steel	Air - Indoor Uncontrolled	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5.1-100	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A
Seals And Roofing	Flood Barrier Pressure Boundary Shelter, Protection	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-15: Reactor Building – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Siding	Pressure Boundary Shelter, Protection	Aluminum	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.B2.T-37b	3.5.1-100	A
Spent Fuel Pool Gates	Pressure Boundary	Stainless Steel	Treated Water	Loss of Material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.A-98	3.3.1-125	D
Spent Fuel Storage Racks	Structural Support	Stainless Steel	Treated Water	Cracking	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.A-96	3.3.1-124	B
Spent Fuel Storage Racks	Structural Support	Stainless Steel	Treated Water	Loss of Material	Water Chemistry (B.2.3.2) One-Time Inspection (B.2.3.20)	VII.A2.A-98	3.3.1-125	B
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A2.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A2.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-16: Structures Affecting Safety – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A

Table 3.5.2-16: Structures Affecting Safety – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A

Table 3.5.2-16: Structures Affecting Safety – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Interior Walls, Ceilings, and Roof	Flood Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-17: Turbine Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A

Table 3.5.2-17: Turbine Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1

Table 3.5.2-17: Turbine Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Interior Walls, Ceilings, and Roof	Flood Barrier HELB Barrier Missile Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Indoor Uncontrolled	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Doors	Flood Barrier HELB Barrier	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Expansion Plugs	Flood Barrier	Aluminum	Air – Indoor Uncontrolled	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.B5.T-37b	3.5.1-100	A
Joint and Penetration Seals	Flood Barrier HELB Barrier Shelter, Protection	Elastomer	Air – Indoor Uncontrolled Air – Outdoor	Loss of Sealing	Structures Monitoring (B.2.3.33)	III.A6.TP-7	3.5.1-072	A
Joint and Penetration Seals	Flood Barrier HELB Barrier	Grout	Air – Indoor Uncontrolled Air – Outdoor	Reduction in Concrete Anchor Capacity	Structures Monitoring (B.2.3.33)	III.B2.TP-42	3.5.1-055	A

Table 3.5.2-17: Turbine Building – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Masonry (Block) Walls	Flood Barrier HELB Barrier Missile Barrier Radiation Shielding Structural Support	Concrete Block	Air – Indoor Uncontrolled Air – Outdoor	Cracking	Masonry Walls (B.2.3.32)	III.A3.T-12	3.5.1-070	A
Miscellaneous Structural Components	Flood Barrier	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Indoor Uncontrolled Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

Table 3.5.2-18: Underground Duct Bank – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-27	3.5.1-065	A
Concrete: Basemat, Foundation (Accessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Distortion	Structures Monitoring (B.2.3.33)	III.A3.TP-30	3.5.1-044	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-29	3.5.1-067	A

Table 3.5.2-18: Underground Duct Bank – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-212	3.5.1-065	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Groundwater/Soil	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-108	3.5.1-042	A
Concrete: Basemat, Foundation (Inaccessible)	Structural Support	Concrete (Reinforced)	Water – Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-67	3.5.1-047	A, 1
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-25	3.5.1-054	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Loss of Bond Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-26	3.5.1-066	A
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air - Outdoor	Cracking Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-23	3.5.1-064	A

Table 3.5.2-18: Underground Duct Bank – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Concrete: Exterior Walls and Roof (Accessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Water - Flowing	Increase in Porosity and Permeability Loss of Strength	Structures Monitoring (B.2.3.33)	III.A3.TP-24	3.5.1-063	A, 1
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking	Structures Monitoring (B.2.3.33)	III.A3.TP-204	3.5.1-043	A
Concrete: Exterior Walls and Roof (Inaccessible)	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Concrete: Interior Walls, Ceilings, and Roof	Flood Barrier Shelter, Protection Structural Support	Concrete (Reinforced)	Air – Outdoor	Cracking Increase in Porosity and Permeability Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-28	3.5.1-067	A
Manhole Covers, Supports	Flood Barrier Missile Barriers Shelter, Protection	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A

Table 3.5.2-18: Underground Duct Bank – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Manhole Covers, Supports	Flood Barrier Missile Barriers Shelter, Protection	Steel	Groundwater/Soil	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-219	3.5.1-079	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.B4.TP-43	3.5.1-092	A
Miscellaneous Structural Components	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-302	3.5.1-077	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-248	3.5.1-080	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	III.A3.TP-274	3.5.1-082	A
Structural Bolting	Structural Support	Steel	Air – Outdoor	Loss of Preload	Structures Monitoring (B.2.3.33)	III.A3.TP-261	3.5.1-088	A

General Notes

A. Consistent with component, material, environment, aging effect, and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

Plant-Specific Notes

1. Groundwater is considered to be water-flowing.

3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION & CONTROLS

3.6.1 Introduction

This section provides the results of the AMR for the electrical commodities identified in Table 2.5-2 of Section 2.5 as being subject to an AMR. The commodities addressed in this section include:

- Insulated Cables and Connections Not Included in the Environmental Qualification (10 CFR 50.49) program
  - Cable connections (metallic parts) not subject to 10 CFR 50.49 EQ requirements
  - Insulated cables and connections not subject to 10 CFR 50.49 EQ requirements
  - Sensitive instrumentation circuits cables and connections not subject to 10 CFR 50.49 EQ requirements
  - Inaccessible and underground medium-voltage (2 kV to 35 kV) power cables (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) not subject to 10 CFR 50.49 EQ requirements
  - Inaccessible and underground I&C cables (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) not subject to 10 CFR 50.49 EQ requirements
  - Inaccessible and underground low-voltage (typical operating voltage of less than 1,000V, but no greater than 2 kV) power cables (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) not subject to 10 CFR 50.49 EQ requirements
- Electrical and I&C penetration assemblies not subject to 10 CFR 50.49 EQ requirements
- Fuse holders, metallic clamps (not part of an active assembly)
- High-voltage electrical insulators
- Metal enclosed bus
- Switchyard bus and connections
- Transmission conductors and connectors

Table 3.6-1, Summary of Aging Management Evaluations for Electrical Commodities, provides the AMRs and the programs evaluated in NUREG-2191 for electrical commodities. This table uses the format described in the introduction to Section 3. Links are provided to the program evaluations in Appendix B.

3.6.2 Results

Table 3.6.2-1, Electrical Commodities Summary of Aging Management Evaluation, presents the results of AMRs and the NUREG-2191 comparison for electrical commodities.

3.6.2.1 Materials, Environments, Aging Effects Requiring Management, and Aging Management Programs

The following sections list the materials, environments, aging effects requiring management, and AMPs for electrical commodities subject to AMR. Programs are described in Appendix B. Further details are provided in Table 3.6.2-1.

Materials

Electrical commodities subject to AMR are constructed of the following materials:

- Aluminum
- Aluminum Alloy
- Cement
- Copper
- Elastomers
- Fiberglass
- Galvanized Steel
- Malleable Iron
- Metallic Clamp – Various Metals Used for Electrical Connections
- Polymers, Silicone Rubber
- Porcelain; Xenoy; Thermo-Plastic Organic Polymers
- Stainless Steel
- Steel
- Various Metals Used for Electrical Bus and Connections
- Various Metals Used for Electrical Contacts
- Various Organic Polymers

Environment

The commodities subject to AMR are exposed to the following environments:

- Air - Indoor Controlled
- Air - Indoor Uncontrolled
- Air - Outdoor
- Adverse Localized Environment Caused by Significant Moisture
- Adverse Localized Environment Caused by Heat, Radiation, or Moisture

Aging Effects Requiring Management

The following aging effects associated with the electrical commodities require management:

- Increased Electrical Resistance of Connection
- Reduced Electrical Insulation Resistance (IR)
- Surface Cracking, Crazing, Scuffing, Dimensional Change, Shrinkage, Discoloration, Hardening and Loss of Strength
- Loss of Material

Aging Management Programs

The following AMPs will manage the effects of aging on electrical commodities:

- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.36)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.3.37)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.38)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.39)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.40)
- Metal-Enclosed Bus (B.2.3.41)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.42)

3.6.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2192 indicates that further evaluation is necessary for certain aging effects and programs identified in Section 3.6.2.2 of NUREG-2192. The following sections, numbered corresponding to the discussions in NUREG-2192, present the MNGP evaluation of the areas requiring further evaluation. Programs are described in Appendix B. Italicized text is taken directly from NUREG-2192.

Aging Management Review Results for Which Further Evaluation Is Recommended by the Generic Aging Lessons Learned for Subsequent License Renewal Report

The basic acceptance criteria defined in Section 3.6.2.1 need to be applied first for all of the AMRs and AMPs reviewed as part of this section. In addition, if the GALL-SLR Report AMR item to which the SLRA AMR item is compared identifies that "further evaluation is recommended," then additional criteria apply as identified by the GALL-SLR Report for each of the following aging effect/aging mechanism combinations. Refer to Table 3.6-1, comparing the "Further

Evaluation Recommended" and the "GALL-SLR Item" column, for the AMR items that reference 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. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed separately in Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," of this SRP-SLR.

Electrical equipment EQ analyses are TLAAs as defined in 10 CFR 54.3. TLAAs are evaluated in accordance with 10 CFR 54.21(c) and addressed in NUREG 2192, Section 4.4. The evaluation of this TLAA is addressed in Section 4.4, *Environmental Qualification of Electric Equipment*, of this application. EQ components are subject to replacement based on a qualified life. Therefore, in accordance with 10 CFR 54.21(a)(1)(ii), EQ components are not subject to AMR.

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).

The discussion in NUREG-2192 addresses aging effects on cable bus. Cable bus is a variation on MEB which is similar in construction to a MEB, but instead of segregated or non-segregated electrical buses, cable bus comprises a metallic cable tray enclosure that utilizes three-phase insulated power cables installed on insulated support blocks. Cable bus is not utilized at MNGP, and therefore, NUREG-2192 aging effects are not applicable. Section 2.5.1.3 contains additional information on cable bus.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload for Transmission Conductors, Switchyard Bus, and Connections

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The 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 the SRP-SLR).

The transmission conductors, transmission connectors, and switchyard bus and connections evaluated for MNGP are those that are part of the circuits which supply power from electric utility transmission system to plant buses. These circuits provide power to in scope license renewal components used for recovery from a station blackout event.

Transmission conductors are uninsulated, stranded electrical cables used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as active disconnect switches, power circuit breakers, and transformers and passive switchyard bus. The transmission conductor commodity group includes the associated fastening hardware but excludes the high-voltage insulators which are evaluated separately.

MNGP transmission conductors and connections subject to AMR are those associated with the off-site power recovery paths following a SBO and are depicted in Figure 2.5-1. The MNGP power path for restoration of offsite power following an SBO event utilizes 336.4 Thousands of Circular Mils (MCM) ACSR overhead transmission lines from the 115 kV 1RTR transformer disconnect switch to the 115 kV/4.16 kV 1R reserve transformer. Other transmission conductors are not subject to AMR since they do not perform a SLR intended function.

Switchyard bus is the uninsulated, unenclosed, rigid electrical conductor or pipe used in switchyards and switching stations to connect two or more elements of an electrical power circuit, such as active disconnect switches and passive transmission conductors. Switchyard bus includes the hardware used to secure the bus to high-voltage electrical insulators. Switchyard bus is subject to AMR if it is credited for recovery of offsite power following an SBO event.

MNGP switchyard bus and connections subject to AMR are those associated with the off-site power recovery paths following a SBO and are depicted in Figure 2.5-1. There is in scope 345 kV switchyard bus in (1) the circuit between 345 kV boundary breakers 8N10, 8N11, 8N7, and 8N4 and the high side of the 2R auxiliary transformer and (2) the circuit between 345 kV circuit breaker 8N11 and the 1ARS transformer disconnect. There is in scope 115 kV switchyard bus in the circuit between the 115 kV boundary breakers 5N5 and 5N7 and the high side of the 1R auxiliary transformer. There is in scope 13.8 kV switchyard bus in the circuit between the 13.8 kV breakers 1N6 and 1N2 and the high side of 1AR reserve auxiliary transformer. Other switchyard bus and connections are not subject to AMR since they do not perform a SLR intended function.

Loss of Material (wear due to wind-induced abrasion)

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 SPEO.

Wind loading that can cause a transmission line and insulators to vibrate is considered in the design and installation of transmission conductors at MNGP.

A review of industry OE and NRC generic communications related to the aging of transmission conductors confirmed that no additional aging effects exist beyond those previously identified. A review of plant-specific OE did not identify any occurrences of loss of material due to wind loading nor unique aging effects for transmission conductors.

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 SPEO.

At MNGP, switchyard bus is rigid bus does not sway because it is supported by station post insulators and ultimately by static, structural components such as concrete footings and structural steel. Switchyard bus is connected to active equipment by short sections of conductors. The flexible conductors dampen the minor vibrations associated with the active switchyard components to the switchyard bus.

Wind loading can cause transmission conductor vibration, or sway. At MNGP, connections between switchyard bus and other switchyard components are made by short transmission conductor jumper cables. Wind loading is not applicable to the short transmission conductor jumper cables due to their short length. As a result, loss of material (wear) caused by cause by wind abrasion or switchyard bus vibration is not an aging effect requiring management because it is precluded by MNGP design.

A review of plant-specific OE did not identify any occurrences of loss of material due to wind induced abrasion nor unique aging effects for switchyard bus. Based on industry experience and MNGP design and OE, the loss of material aging effect that could result from wind-induced abrasion is not applicable and would not cause a loss of intended function for switchyard bus for the SPEO.

Therefore, loss of material due to wear of transmission conductors and switchyard bus is not an aging effect requiring management at MNGP.

Loss of Conductor Strength (Corrosion)

This aging effect only applies to aluminum conductor steel reinforced (ACSR) transmission conductors. In-scope transmission conductors at MNGP are for the 336.4 MCM ACSR circuit between the 115 kV, 1RTR, transformer disconnect and the high side of the 1R reserve transformer which is used for recovery of offsite power following an SBO event. See Figure 2.5-1.

The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR transmission conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion in ACSR conductors is a very slow-acting aging mechanism with the corrosion rate depending largely on air quality. Air quality factors include suspended particle chemistry, sulfur dioxide (SO_2) concentration, precipitation, fog chemistry, and meteorological conditions. Air quality in rural areas, such as the area surrounding MNGP, generally contains low concentrations of suspended particles and SO_2, which minimizes the corrosion rate.

There are no major industries within the immediate vicinity of MNGP. The site is in the town of Monticello in Wright County, Minnesota, about 42 miles northwest of the center of the city of Minneapolis. MNGP is located in a rural area and is not in proximity to saltwater environments. Wright County is predominately rural. The nearest industrial facility, which discharges airborne particulates, is the coal-fired SHERCO Electrical Generating Plant locating about 5 miles northwest of the plant. Since the plant began operation in 1971, there has not been any regularly scheduled maintenance to remove surface contamination from the switchyard bus or transmission line insulators, providing evidence that this coal-fired plant is not a source or concern regarding transmission conductor corrosion.

Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion.

There is set percentage of composite conductor strength established at which a transmission conductor is replaced. As illustrated below, there is ample strength margin to maintain the transmission conductor intended function through the SPEO.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. MNGP transmission conductors within the scope of this evaluation are designed and installed in accordance with the NESC. The following evaluation of the conductor type with the smallest ultimate strength margin (4/0 ACSR) in the NESC will be used as an illustration.

The ultimate strength and the NESC heavy load tension requirements of 4/0 ACSR are 8350 lbs. and 2761 lbs. respectively. The margin between the NESC heavy load and the ultimate strength is 5589 lbs.; i.e., there is a 67 percent of ultimate strength margin. The Ontario Hydroelectric study showed a 30 percent loss of composite conductor strength in an 80-year-old conductor. In the case of the 4/0 ACSR transmission conductors, a 30 percent loss of ultimate strength would mean that there would still be a 37 percent ultimate strength margin between what is required by the NESC and the actual conductor strength.

The 4/0 ACSR conductor has the lowest initial design margin of transmission conductors included in this review. This illustrates with reasonable assurance that transmission conductors will have ample strength through the SPEO. This illustrates with reasonable assurance that transmission conductors will have ample strength through the SPEO.

A review of industry OE and NRC generic communications related to the aging of transmission conductors confirmed that no additional aging effects exist beyond those previously identified. A review of plant-specific OE did not identify any issues with transmission conductor corrosion or unique aging effects for transmission conductors.

Therefore, loss of conductor strength is not an aging effect requiring management for transmission conductors at MNGP.

<u>Increased Resistance of Connection (Oxidation)</u>

Increased connection resistance due to surface oxidation is an applicable aging effect, but it is not significant enough to cause a loss of intended function. The aluminum, steel, stainless steel, and steel alloy components in the MNGP switchyard are exposed to precipitation, but these components do not experience any appreciable aging effects in this environment, except for minor oxidation, which does not impact the ability of the connections to perform their SLR intended function. At MNGP, switchyard connection surfaces are coated with an antioxidant compound (i.e., a grease-type sealant) prior to tightening the connection to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connections, thus minimizing the potential for corrosion. Based on plant-specific and industry wide OE, this method of installation has proven to provide a corrosion-resistant low electrical resistance connection. In addition, MNGP periodically performs infrared inspections of the switchyard connections to verify the integrity of the connections. The infrared inspections of the switchyard connections verify the effectiveness of the connection design and site installation practices. These inspections and the absence of plant-specific OE verifies that this aging effect is not significant for MNGP.

Therefore, increased connection resistance due to general corrosion resulting from oxidation of switchyard connection metal surfaces is not an aging effect requiring management at MNGP.

Increased Resistance of Connection (Loss of Preload)

Increased connection resistance due to loss of pre-load (torque relaxation) for switchyard connections is not an aging effect requiring management. The EPRI license renewal tools do not list loss of pre-load as an applicable aging mechanism. The design of transmission conductor and switchyard bus bolted connections precludes torque relaxation as confirmed by plant-specific OE. A plant-specific review of OE did not identify any failures of switchyard connections. The design of switchyard bolted connections includes Belleville washers and an anti-oxidant compound (i.e., a grease-type sealant) to preclude connection degradation. The type of bolting plate and the use of Belleville washers is the industry standard to preclude torque relaxation. This design configuration, combined with the proper sizing of mounting hardware, eliminates the need to consider this aging mechanism. Therefore, increased connection resistance due to loss of pre-load on switchyard connections is not an aging effect requiring management.

Bolted connections for transmission conductors and switchyard bus, in-scope transmission conductors and switchyard bus connections at MNGP are limited to equipment for recovery of offsite power following an SBO event. Routine inspections of the MNGP switchyard and transformers include performing periodic infrared inspections of this power path to verify the integrity of the connections. These inspections and the absence of plant-specific OE demonstrates that this aging effect is not significant for MNGP.

Therefore, increased connection resistance due to loss of pre-load of transmission conductor and switchyard bus connections is not an aging effect requiring management for MNGP.

Conclusion

There are no applicable aging effects that could cause a loss of the intended function of the transmission conductors and connections and switchyard bus and connections. Therefore, there are no aging effects requiring management for MNGP transmission conductors and connections and switchyard bus and connections during the SPEO.

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Acceptance criteria are described in BTP IQMB-1 (Appendix A.2 of the SRP-SLR).

QA provisions applicable to SLR for MNGP are discussed in Appendix B.

3.6.2.2.5 Ongoing Review of Operating Experience

Acceptance criteria are described in Appendix A.4, "Operating Experience for Aging Management Programs."

The OE process and acceptance criteria are described in Section B.1.4.

3.6.2.3 AMR Results for Which Further Evaluation is Not Recommended by the GALL-SLR Report

3.6.2.3.1 Fuse Holders

Table 3.6.1, item numbers 3.6.1-016, 3.6.1-017, and 3.6.1-018 – Fuse Holders (not part of active equipment) Metallic Clamps: Potential aging effects for the metallic clamps of fuse holders, not part of active equipment were evaluated to determine if the GALL-SLR report XI.E5, *Fuse Holders* AMP was to be implemented for MNGP SLR.

Fuse holders are in scope for license renewal at MNGP by meeting (a)(1), (a)(2) functional, or (a)(3) license renewal 10 CFR 54.4 scoping criteria. In accordance with the bounding approach described in NEI 17-01, the fuse holders are an electrical commodity group and are assessed for AMR by applying the criteria of 10 CFR 54.21(a)(1)(i). The resulting fuse holder population evaluated for aging effects are those that are passive and long lived; i.e., those that are not part of active equipment or assembly. The passive, long lived fuse holders that screen in are evaluated to determine if they are subject to:

- adverse environmental conditions that could cause an increase in electrical resistance of connection,
- fatigue from ohmic heating, thermal cycling, or electrical transients, or
- fatigue from frequent fuse removal/manipulation or vibration.

A systematic review of the fuse holders: metallic clamps was performed for MNGP, considering the above scoping and screening criteria and aging effects and mechanisms. The list of fuses/fuse holders for consideration was compiled from fuse and fuse holder components a list of fuse holders was compiled from various databases including SAP and Cable and Raceway Information System, analysis/CAs, plant modifications since the initial LRA, and plant personnel knowledge. The results of the review identified 48 fuse holders that require AMR.

<u>Fire Protection System</u>

Twenty-seven fuse holders found in two different enclosed electrical boxes serve the fire protection fire zone fuse panels located in the turbine building and the reactor building.

The potential aging effects as discussed in NUREG-2192 are not applicable to these fuse holders. The evaluation of aging effects is discussed below.

<u>*Chemical Contamination, Corrosion, and Oxidation*</u>

The electrical boxes in the MNGP Reactor building on the 935-ft elevation south of the main access and turbine building 931-ft elevation north of Motor Control Center (MCC) 142 rooms are in an environment that does not subject them to environmental aging mechanisms. They are located inside the power block. The fuse holders are protected from chemical contamination and are within a mild environment inside the power block during normal conditions. There are no sources of uncontrolled chemicals near the electrical boxes during normal conditions. The environment inside the rooms is air indoor controlled and air indoor uncontrolled; they do not experience high relative humidity during normal conditions. The fuse holders are not subject to outside weather conditions and therefore, are not subject to moisture from precipitation. The fuse holders are not located in or near humid areas and they are not exposed to industrial or oceanic environments.

A walkdown of these electrical boxes containing the in-scope fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion.

Therefore, chemical contamination, corrosion, and oxidation are not considered applicable aging mechanisms for these fuse holders.

Ohmic Heating, Thermal Cycling, and Electrical Transients

Fuse holders for circuits that carry significant current in power applications could potentially be exposed to thermal fatigue in the form of high resistance caused by thermal cycling and ohmic heating. The loads fed from these panels are control circuits that operate at low currents. Control power circuits characteristically operate at low currents where no appreciable thermal cycling or ohmic heating occurs. Therefore, ohmic heating and thermal cycling is not considered an applicable aging mechanism for these fuse holders.

Mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. The CAP is used to document adverse conditions and provides corrective actions associated with electrical faults and transients that cause the actuation of circuit protective devices. Therefore, electrical transients are not considered an applicable aging mechanism for these fuse holders.

Frequent Manipulation and Vibration

Wear and fatigue are caused by repeated insertion and removal of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e. removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing or preventative maintenance (PM). Additionally, if fuses are manipulated for non-routine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse clips.

These fuse holders are in electrical boxes that are not mounted on moving or rotating equipment such as compressors, fans, or pumps. Because the electrical boxes are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the metallic clamps of these fuse holders will not exhibit the aging effects/mechanisms of fatigue due to frequent manipulation or vibration.

Substation

Three fuse panels consisting of six fuses, six fuses, and nine fuses each feed the Direct Current (DC) electrical power circuits in the Substations and Transformer system for potential transformers. The fuse boxes are located, in the yard at the 8N4 breaker, 115 kV bus 1, 345 kV bus 1.

The potential aging effects as discussed in NUREG-2192 are not applicable to these fuse holders. The evaluation of aging effects is discussed below.

Chemical Contamination, Corrosion, and Oxidation

The electrical boxes in the 345 kV and 115 kV substation electrical boxes are in an environment that does not subject them to environmental aging mechanisms.

The fuse holders are located inside their respective electrical boxes in the switchyard. There are no sources of uncontrolled chemicals near the electrical boxes during normal conditions. They are not exposed to industrial or oceanic environments. The electrical boxes are NEMA 4 which is indoor or outdoor use and provides protection inside the enclosure against ingress of solid foreign objects including dirt and windblown dust. This also provides protection inside the enclosure from rain, sleet, snow, splashing water, hose directed water, and external formation of ice on the enclosure.

A walkdown of these electrical boxes containing the in-scope fuse holders confirmed that these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion.

Therefore, chemical contamination, corrosion, and oxidation are not considered applicable aging mechanisms for these fuse holders.

Ohmic Heating, Thermal Cycling, and Electrical Transients

Fuse holders for circuits that carry significant current in power applications could potentially be exposed to thermal fatigue in the form of high resistance caused by thermal cycling and ohmic heating. The loads fed from these panels are control circuits that operate at low currents. Control power circuits characteristically operate at low currents where no appreciable thermal cycling or ohmic heating occurs. Therefore, ohmic heating and thermal cycling is not considered an applicable aging mechanism for these fuse holders.

Mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. The CAP is used to document adverse conditions and provides corrective actions associated with electrical faults and transients that cause the actuation of circuit protective devices. Therefore, electrical transients are not considered an applicable aging mechanism for these fuse holders.

Frequent Manipulation and Vibration

Wear and fatigue are caused by repeated insertion and removal of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e. removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing or preventative maintenance. Additionally, if fuses are manipulated for non-routine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse clips.

These fuse holders are in electrical boxes that are not mounted on moving or rotating equipment such as compressors, fans, or pumps. Because the electrical boxes are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the metallic clamps of these fuse holders will not exhibit the aging effects/mechanisms of fatigue due to frequent manipulation or vibration.

Summary of Aging Management Review Results

There are 48 fuse holders in scope for SLR that are not part of active equipment at MNGP that are subject to AMR. Based on installed location, design configuration, operating service conditions, and OE, the five fuse panels located in the MNGP power block and 345 kV and 115 kV substation are not susceptible to the aging effects and mechanisms associated with metallic clamps.

Therefore, aging management activities are not required for these fuse holders (not part of active equipment): metallic clamps at MNGP.

MNGP fuse holders (not part of active equipment): insulation material that may be subject to an ALE that may affect insulation resistance are addressed as part of Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements. Fuse holder insulation material that is not subject to an adverse environment does not have aging effects requiring management.

Conclusion

Aging management activities for MNGP fuse holders (not part of an active equipment): metallic clamps are not required for the SPEO; therefore, the GALL-SLR report XI.E5 “Fuse Holders” AMP is not applicable to MNGP for the SPEO.

The evaluations for the first period of extended operation (PEO) concluded that the fuse holders did not require aging management activities to continue to perform their intended function during the first PEO. Consistent with the evaluations performed for the first PEO, there are no aging effects requiring management that would cause a loss of intended function if left unmanaged for the SPEO.

3.6.2.3.2 High-Voltage Electrical Insulators

The MNGP in scope high-voltage electrical insulators (HVIs) were evaluated for aging effects requiring management during AMRs. The HVIs in scope for license renewal are located in the offsite power source circuits and the alternate AC source for the SBO. The in-scope insulators include:

- 345 kV, 115 kV and 13.8 kV post insulators in offsite source paths.
- 115 kV strain insulators in offsite source paths.

The in scope HVIs provide electrical insulation for switchyard bus, transmission conductors, switchyard active components, and associated connections that are part of the circuits that supply power from electric utility transmission system to plant buses. These circuits provide power to in scope license renewal components used for recovery from a station blackout event.

Surface Contamination

Various airborne materials such as dust, salt and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and, in most areas, 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 proximity to the seacoast where salt spray is prevalent, dust near industrial facilities that discharge airborne pollutants, or at sites where the cooling tower plume may deposit contaminants on switchyard components and transmission lines.

At MNGP, the in scope HVIs; the 345 kV, 115 kV, 13.8 kV post insulators, and 115 kV strain insulators were evaluated for susceptibility to airborne surface contamination from salt, dust, fog, cooling tower plume, foreign debris, and industrial effluents. MNGP is not located in an environment conducive to accelerated aging. Considering potential airborne salt contamination, the HVIs are not located near a seacoast or near a brackish waterway. MNGP is located in Wright County which is predominately a rural area. Considering airborne particulate contamination, the nearest industrial facility, which discharges any significant amount of airborne particulates, is the coal-fired SHERCO Electrical Generating Plant locating about five miles northwest of the plant. These airborne particulates pose no contamination risk to the scope of HVIs because of the physical distance between the coal-fired plant and the MNGP switchyard. Considering potential cooling tower plume contamination, the cooling towers at MNGP are located along the river, at the north east end of the site. The plume from these cooling towers poses no contamination risk to the in scope HVIs because the mechanical cooling towers that are approximately 50 feet in height and are not directly next to the nearest in scope HVIs. These plumes quickly dissipate before reaching the nearest in scope HVIs. Considering potential foreign debris, the HVIs are located in rural area with no heavy industry or urban population centers.

Fog, in and of itself, is not a contaminant for HVIs. Therefore, surface contamination from fog is not an aging effect, is not subject to an AMR, and does not require aging management.

A nine-year search of OE for HVIs was performed. Cumulative build up HVI contamination has not been experienced at MNGP. Additionally, there are no existing preventive maintenance or inspection tasks that are taking preventative measures to preclude an occurrence of excessive HVI surface contamination.

Based on MNGP locations, lack of substantial airborne contaminants, and its corroborating OE, excessive HVI surface contamination has not occurred and is not expected to occur during the SPEO. Therefore, HVI surface contamination is not a significant aging effect for MNGP. The aging effects of surface contamination from salt, dust, fog, cooling tower plume, foreign debris, and industrial effluents are not applicable to MNGP for the SPEO. No aging management activity is required for the HVIs due to airborne contamination.

Similar to porcelain high-voltage electrical insulators, various airborne contaminates such as dust, salt, or industrial effluent can contaminate MNGP polymer high-voltage electrical insulator surfaces leading to reduced insulation resistance. The buildup of surface contamination is gradual and, in most cases, removed by rainfall. The silicone rubber of the polymer high-voltage insulator is superior to porcelain due to its hydrophobic properties. Hydrophobicity is the surface property that causes a water drop to form a bead. Silicone rubber is naturally hydrophobic, has excellent resistance to UV, electrical aging, corona effect, and minimizes leakage currents on the surface of the insulator, all of which help polymer insulators perform well in contaminated environments. Silicone rubbers are characterized by having a low surface energy that results in highly hydrophobic surfaces. This property prevents the insulator surface from becoming completely wet, thereby suppressing leakage currents under contaminated conditions. Water deposited on the surface of the rubber cannot dissolve the encapsulated contamination thereby preventing the formation of a conductive film. The lightweight silicone chains in the rubber surface material impregnate the contaminant layer, making it hydrophobic as well which is what gives the silicone rubber superior contamination performance. Consequently, silicone rubber insulators can withstand high levels of contamination minimizing the potential aging effects from swelling of silicone rubber layer due to chemical contamination, sheath wetting caused by chemicals absorbed by oil from silicone rubber compound, and chalking and crazing of the insulator surface resulting in contamination, arcing, and flash over. The insulators hydrophobic surfaces are also effective in the mitigation of aggressive environments such as excrement from birds. OE reviews and results of periodic switchyard inspections have not identified issues with surface contamination for polymer high-voltage insulators. Consequently, the rate of contamination buildup on MNGP polymer high-voltage electrical insulators is not significant enough to cause a loss of intended function during the SPEO.

Porcelain cracking or breaking is most commonly caused by an object striking the HVI. 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. Plant specific OE shows that porcelain cracking due to cement growth has not occurred at MNGP. Therefore, cracking caused by physical damage is not an aging effect, is not subject to an AMR, and does not require aging management.

Loss of Material - Mechanical Wear

Loss of material of HVIs can occur due to oscillating movement of transmission conductors due to significant and sustained winds. Significant wind can result in mechanical wear of metallic parts. Surface corrosion of HVI metallic parts can also occur due to environmental contamination or 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. If this swinging is frequent enough, it could cause wear in the metal contact points of the insulator string.

The HVIs to be evaluated for aging effects due to movement of transmission conductors due to significant wind are those conductors with strain or suspension HVIs, which for MNGP, only include high-voltage transmission conductors. The in-scope strain insulators are for the 115 kV transmission connection conductor routed between the MNGP substation and the reserve transformer 1R. The 115 kV transmission conductors are a connection span of three 336.4 MCM ACSR conductors. The transmission and distribution design practices follow the National Electrical Safety Code (NESC) methodologies. The NESC sets the maximum tension of a conductor to withstand heavy load requirements which includes consideration of oscillating movement of transmission conductors due to significant wind.

Although this loss of material due to mechanical wear of the metallic parts of HVIs is possible, experience has shown that the transmission conductors do not normally swing and that when they do, due to significant wind, they do not continue to swing for very long once the wind has subsided. Wind loading, that can cause a transmission line to sway, is considered and minimized during design and installation.

In addition, the installed configuration of the strain insulators minimizes movement. This reduces mechanical wear of metallic parts within the strain insulators such that these metallic contact points do not require inspection for mechanical wear. Therefore, aging effects due to loss of material due to mechanical wear is not applicable to MNGP for the SPEO.

Conclusion

Aging management activities for MNGP high-voltage electrical insulators are not required for the SPEO; therefore, the GALL-SLR report XI.E7 “High Voltage Insulators” AMP is not applicable to MNGP.

In addition, to support this conclusion, in accordance with NUREG-2192 requirements, the SSCs including the HVI required to cope with, and recover from, the SBO event are included within the scope of SLR. These SLR boundaries include components credited to cope with, and recover from, the SBO event were established based on MNGP CLB consistent with the initial LRA and aligned with the SLR scoping methodology. These HVIs are documented as an electrical commodity that the AMR determined the aging effect to be none and, therefore, no aging management activity is required for the HVIs. The evaluations for the first PEO concluded that the HVIs did not require aging management activities to continue to perform their intended function during the first PEO. Consistent with the evaluations performed for the first PEO, airborne contamination and loss of material due to mechanical wear or corrosion are not aging effects requiring management in that they would not cause a loss of intended function if left unmanaged for the SPEO.

3.6.2.4 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the electrical and I&C commodities:

- Section 4.4, *Environmental Qualification of Electrical Equipment*

3.6.3 <u>Conclusion</u>

Electrical commodities that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). AMPs selected to manage aging effects for electrical and I&C commodities are identified in Section 3.6.2.1 and in the following tables.

A description of AMPs is provided in Appendix B, along with the demonstration that the identified aging effects will be effectively managed.

Based on the demonstrations provided in Appendix B, the effects of aging associated with electrical commodities will be managed such that the intended functions will be maintained consistent with the CLB during the SPEO.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6.1-001	Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of various polymeric and metallic materials in plant areas subject to a harsh environment (i.e., loss of coolant accident (LOCA), high energy line break (HELB), or post LOCA environment or, an ALE for the most limiting qualified condition for temperature, radiation, or moisture for the component material (e.g., cable or connection insulation).	Various aging effects due to various mechanisms in accordance with 10 CFR 50.49	EQ is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.4, "Environmental Qualification (EQ) of Electrical 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 Components," of this report for meeting the requirements of 10 CFR 54.21(c)(1)(i)-(iii).	Yes, TLAA (SRP-SLR Section 3.6.2.2.1)	Consistent with NUREG-2191. EQ equipment is not subject to AMR because the equipment is subject to replacement based on a qualified life. EQ analyses are evaluated as TLAAs in Section 4.4.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**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; fiberglass, aluminum alloy exposed to air - outdoor	Loss of material on metallic connectors due to mechanical wear caused by movement of transmission conductors due to significant wind	AMP XI.E7,"High-Voltage Insulators"	No	Not applicable. Based on the MNGP design and OE, loss of material is not an applicable aging effect for high voltage electrical insulators in electrical commodities. In scope high voltage insulators comprised of porcelain, malleable iron, aluminum, galvanized steel, and cement in an air - outdoor environment are not subject to loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind. See Section 3.6.2.3.2 for evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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; fiberglass, aluminum alloy exposed to air - outdoor	Reduced 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 MNGP geographic location, design, and OE, reduced insulation resistance is not an applicable aging effect for high-voltage electrical insulators in electrical commodities. In scope high-voltage electrical insulators comprised 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, or industrial effluent contamination. See Section 3.6.2.3.2 for evaluation.
3.6.1-004	Transmission conductors composed of aluminum; steel exposed to air - outdoor	Loss of conductor strength due to corrosion	A plant-specific aging management program is to be evaluated for ACSR	Yes, (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to MNGP. See Section 3.6.2.2.3 for further evaluation.
3.6.1-005	Transmission connectors composed of aluminum; steel exposed to air - outdoor	Increased resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes, (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to MNGP. See Section 3.6.2.2.3 for further evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-006	Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air - outdoor	Loss of material due to wind induced abrasion; Increased electrical resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes, (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to MNGP. See Section 3.6.2.2.3 for further evaluation.
3.6.1-007	Transmission conductors composed of aluminum; steel exposed to air - outdoor	Loss of material due to wind-induced abrasion	A plant-specific aging management program is to be evaluated for All Aluminum Conductor (AAC), ACAR and ACSR	Yes, (SRP-SLR Section 3.6.2.2.3)	NUREG-2191 aging effects are not applicable to MNGP. See Section 3.6.2.2.3 for further evaluation.
3.6.1-008	Electrical insulation for electrical cables and connections (including terminal blocks, fuse holders, etc.) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an ALE caused by heat, radiation, or moisture	Reduced insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E1, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Consistent with NUREG-2191. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.36) AMP will manage the effects of aging. This AMP includes inspection of non-EQ electrical and I&C penetration cables and connections. MNGP EQ electrical and I&C penetration assemblies are covered under the Environmental Qualification of Electric Equipment program.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6.1-009	Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an ALE caused by heat, radiation, or moisture	Reduced insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E2, "Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	No	Consistent with NUREG-2191. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.3.37) AMP will manage these aging effects. This AMP includes review of calibration results or surveillance findings for instrumentation circuits.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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, and combined thermoplastic jacket/insulation shield exposed to an ALE caused by significant moisture	Reduced electrical insulation resistance (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.2.3.38) XI.E3A AMP, Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.39) XI.E3B AMP, or the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.40) XI.E3C AMP will manage these aging effects. AMPs include inspection of manholes, verification of sump pump function (if installed), and de-watering activities as required.
3.6.1-011	Metal enclosed bus: enclosure assemblies composed of elastomers exposed to air - indoor controlled or uncontrolled or 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 Structures Monitoring (B.2.3.33) AMP will manage these aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6.1-012	Metal enclosed bus: bus/connections composed of various metals used for electrical bus and connections exposed to air - indoor controlled or uncontrolled or 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.2.3.41) AMP will manage these aging effects.
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 or air - outdoor	Reduced electrical insulation resistance due to thermal / thermoxidative degradation of organics/ thermoplastics radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	AMP XI.E4, “Metal Enclosed Bus”	No	Consistent with NUREG-2191. The Metal-Enclosed Bus (B.2.3.41) AMP will manage these aging effects.
3.6.1-014	Metal enclosed 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	AMP XI.E4, “Metal Enclosed Bus” or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP will manage these aging effects.
3.6.1-015	Metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air - outdoor	Loss of material due to pitting, crevice corrosion	AMP XI.E4, “Metal Enclosed Bus” or AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG-2191. The Structures Monitoring (B.2.3.33) AMP will manage these aging effects.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-016	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air - indoor, uncontrolled	Increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply)	AMP XI.E5, “Fuse Holders” No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation.	No	Pursuant to the discussion in SLRA Section 2.5.1.4, the fuse holders within the scope of SLR are located in air - indoor, air - outdoor environments and are not subject to increased electrical resistance of connection due to chemical contamination, corrosion, and oxidation. See Section 3.6.2.3.1 for evaluation.
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 cheating, thermal cycling, electrical transients.	No	Pursuant to the discussion in SLRA Section 2.5.1.4, the fuse holders within the scope of SLR are not subject to ohmic heating, thermal cycling, or electrical transients. See Section 3.6.2.3.1 for evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.6.1-018	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air - indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/manipulation or vibration	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue caused by frequent fuse removal/manipulation or vibration	No	Pursuant to the discussion in SLRA Section 2.5.1.4, the fuse holders within the scope of SLR are not subject to frequent manipulation and will not experience fatigue degradation (at the metallic clamp). See Section 3.6.2.3.1 for evaluation.
3.6.1-019	Cable connections (metallic parts) composed of various metals used for electrical contacts exposed to air - indoor controlled or uncontrolled or 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.2.3.42) AMP will manage the effects of aging.
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 All Aluminum Conductor (AAC)	No	Not applicable. NUREG-2191 aging effects are not applicable to MNGP. See Section 3.6.2.2.3 for evaluation.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.6.1-022	Fuse holders (not part of active equipment): insulation material composed of electrical insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate, and other, exposed to air - indoor, controlled or uncontrolled	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms	No	There are no aging effects to be managed for bakelite; phenolic melamine or ceramic; or molded polycarbonate insulation material in fuse holders (not part of active equipment) exposed to an air - indoor, controlled environment in electrical commodities.
3.6.1-023	Metal enclosed bus: external surface of enclosure assemblies. Galvanized steel; aluminum. air – indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191.
3.6.1-024	Metal enclosed bus: external surface of enclosure assemblies. Steel air - indoor controlled	None	None	No	Consistent with NUREG-2191.
3.6.1-025	There is no 3.6.1-025 in NUREG-2192.				
3.6.1-026	There is no 3.6.1-026 in NUREG-2192.				

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**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. Cable bus is not utilized at MNGP.
3.6.1-028	There is no 3.6.1-028 in NUREG-2192.				
3.6.1-029	Cable bus: electrical insulation; insulators - exposed to air - indoor controlled or uncontrolled, air - outdoor	Reduced electrical insulation resistance due to degradation caused thermal/ thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes	Not applicable. Cable bus is not utilized at MNGP.
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. Cable bus is not utilized at MNGP.

Table 3.6-1: Summary of Aging Management Evaluations for Electrical Commodities					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**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. Cable bus is not utilized at MNGP.
3.6.1-032	Cable bus: external surface of enclosure assemblies: composed of steel; air - indoor controlled	None	None	No	Not applicable. Cable bus is not utilized at MNGP.

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
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.2.3.42)	VI.A.LP-30	3.6.1-019	A
Electrical Conductor Insulation for Inaccessible Instrumentation and Control Cables (E.G., Installed In Duct Bank, Buried Conduit Or Direct Buried)	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced Electrical Insulation Resistance (IR)	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.39)	VI.A.LP-35b	3.6.1-010	A
Electrical Conductor Insulation for Inaccessible Low-Voltage Cables - Typical Operating Voltage Of <1 kV but No Greater Than 2 kV (e.g., Installed in Duct Bank, Buried Conduit or Direct Buried)	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced Electrical Insulation Resistance (IR)	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.40)	VI.A.LP-35c	3.6.1-010	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Electrical Conductor Insulation for Inaccessible Medium-Voltage Cables -Typical Operating Range of 2 kV to 35 kV (e.g., Installed in Duct Bank, Buried Conduit or Direct Buried)	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced Electrical Insulation Resistance (IR)	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.38)	VI.A.LP-35a	3.6.1-010	A
Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements	Electrical Continuity	Various Metallic Materials	Adverse Localized Environment	Various Aging Effects	Environmental Qualification of Electric Components (B.2.2.3)	VI.B.L-05	3.6.1-001	A
Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements	Electrical Continuity	Various Metallic Materials	10 CFR 50.49 EQ Environments	Various Aging Effects	Environmental Qualification of Electric Components (B.2.2.3)	VI.B.L-05	3.6.1-001	A
Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements	Insulate (Electrical)	Various Polymeric Materials	Adverse Localized Environment	Various Aging Effects	Environmental Qualification of Electric Components (B.2.2.3)	VI.B.L-05	3.6.1-001	A
Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements	Insulate (Electrical)	Various Polymeric Materials	10 CFR 50.49 EQ Environments	Various Aging Effects	Environmental Qualification of Electric Components (B.2.2.3)	VI.B.L-05	3.6.1-001	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Electrical Insulation for Electrical Cables and Connections (Including Terminal Blocks, Fuse Holders etc.)	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Heat, Radiation, or Moisture	Reduced Electrical Insulation Resistance (IR)	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.3.36)	VI.A.LP-33	3.6.1-008	A
Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits that are Sensitive to Reduction in Conductor Electrical Insulation Resistance (IR)	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Heat, Radiation, or Moisture	Reduced Electrical Insulation Resistance (IR)	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits (B.2.3.37)	VI.A.LP-34	3.6.1-009	A
Fuse Holders (Not Part of Active Equipment): Electrical Insulation	Insulate (Electrical)	Electrical Insulation: Bakelite; Phenolic Melamine or Ceramic; Molded Polycarbonate; Other	Air – Indoor Uncontrolled, Air - Outdoor	None	None	VI.A.LP-24	3.6.1-022	G, 1

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Fuse Holders (Not Part of Active Equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air – Indoor Uncontrolled, Air - Outdoor	None	None	VI.A.LP-31	3.6.1-018	G, 2
Fuse Holders (Not Part of Active Equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air – Indoor Uncontrolled, Air - Outdoor	None	None	VI.A.LP-07	3.6.1-017	G, 3
Fuse Holders (Not Part of Active Equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air – Indoor Uncontrolled, Air - Outdoor	None	None	VI.A.LP-23	3.6.1-016	G, 4
High-Voltage Electrical Insulators	Insulate (Electrical)	Porcelain; Malleable Iron; Aluminum; Galvanized Steel; Cement, Toughened Glass; Polymers Silicone Rubber; Fiberglass, Aluminum Alloy	Air – Outdoor	None	None	VI.A.LP-32	3.6.1-002	I, 5

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation

Structure and/or Component	Component Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
High-Voltage Electrical Insulators	Insulate (Electrical)	Porcelain; Malleable Iron; Aluminum; Galvanized Steel; Cement; Toughened Glass; Polymers; Silicone Rubber; Fiberglass, Aluminum Alloy	Air – Outdoor	None	None	VI.A.LP-28	3.6.1-003	I, 6
Metal Enclosed Bus: Bus/Connections	Electrical Continuity	Various Metals Used for Electrical Bus And Connections	Air – Indoor Controlled or Uncontrolled, Air – Outdoor	Increased Electrical Resistance of Connection	Metal-Enclosed Bus (B.2.3.41)	VI.A.LP-25	3.6.1-012	A
Metal Enclosed Bus: Insulation; Electrical Insulators	Insulate (Electrical)	Porcelain; Xenoy; Thermo-Plastic Organic Polymers	Air – Indoor Controlled or Uncontrolled or Air – Outdoor	Reduced Electrical Insulation Resistance (IR)	Metal-Enclosed Bus (B.2.3.41)	VI.A.LP-26	3.6.1-013	A
Metal Enclosed Bus: Enclosure Assemblies	Shelter, Protection	Elastomers	Air – Indoor Controlled or Uncontrolled, Air – Outdoor	Surface Cracking, Crazing, Scuffing, Dimensional Change, Shrinkage, Discoloration, Hardening and Loss of Strength	Structures Monitoring (B.2.3.33)	VI.A.LP-29	3.6.1-011	A

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Galvanized Steel; Aluminum	Air – Indoor Controlled or Controlled	None	None	VI.A.LP-41	3.6.1-023	A
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Galvanized Steel; Aluminum	Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	VI.A.LP-42	3.6.1-015	A
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Steel	Air – Indoor, Controlled	None	None	VI.A.LP-44	3.6.1-024	A
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Steel	Air – Indoor Uncontrolled, Air – Outdoor	Loss of Material	Structures Monitoring (B.2.3.33)	VI.A.LP-43	3.6.1-014	A
Switchyard Bus and Connections	Electrical Continuity	Aluminum; Copper; Bronze; Stainless Steel; Galvanized Steel	Air – Outdoor	None	None	VI.A.LP-39	3.6.1-006	I, 7
Transmission Conductors	Electrical Continuity	Aluminum; Steel	Air – Outdoor	None	None	VI.A.LP-38	3.6.1-004	I, 9

Table 3.6.2-1: Electrical and Instrumentation & Control Commodities – Summary of Aging Management Evaluation								
Structure and/or Component	**Component Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Transmission Conductors	Electrical Continuity	Aluminum; Steel	Air – Outdoor	None	None	VI.A.LP-47	3.6.1-007	I, 10
Transmission Connectors	Electrical Continuity	Aluminum; Steel	Air – Outdoor	None	None	VI.A.LP-48	3.6.1-005	I, 8

General Notes

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG 2191 line item. AMP is consistent with NUREG-2191 AMP description.

G. Environment not in NUREG-2191 for this component and material.

I. Aging effect in NUREG-2191 for this component, material and environment combination is not applicable.

Plant-Specific Notes

1. In alignment with GALL-SLR, no AMP is required when fuse holders are located in an environment that does not subject them to environmental aging mechanisms. Fuse holder insulation material in an ALE is managed via the XI.E1 AMP. MNGP fuse holders (not in active components) insulation material and environment combination has no aging effects requiring management. See SLRA Section 3.6.2.3.1 for additional information.

2. In alignment with GALL-SLR, no AMP is required when fuse holders are not subject to fatigue due to frequent fuse removal/manipulation or removal. See SLRA Section 3.6.2.3.1 for additional information.

3. In alignment with GALL-SLR, no AMP is required when fuse holders are not subject to fatigue due to ohmic heating, thermal cycling, or electrical transients. See SLRA Section 3.6.2.3.1 for additional information.

4. In alignment with GALL-SLR, no AMP is required when 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. See SLRA Section 3.6.2.3.1 for additional information.

5. Based on MNGP design and a review of OE, loss of material is not an applicable aging effect for MNGP high-voltage electrical insulators. MNGP high-voltage electrical insulators within the scope of license renewal are not subject to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind. See SLRA Section 3.6.2.3.2 for additional information.

6. Based on MNGP design and a review of OE, reduced electrical insulation resistance is not an applicable aging effect for MNGP high-voltage electrical insulators. MNGP high-voltage electrical insulators within the scope of license renewal are not subject to reduced insulation resistance due to the presence of cracks, foreign debris, salt, dust, cooling tower plume, or industrial effluent contamination. See SLRA Section 3.6.2.3.2 for additional information.

7. Based on MNGP design and a review of OE, loss of material and increased resistance of connection are not applicable aging effects for MNGP switchyard bus and connections. MNGP switchyard bus and connections within the scope of license renewal are not subject to wind-induced abrasion nor oxidation or loss of pre-load. See SLRA Section 3.6.2.2.3 for additional information.

8. Based on MNGP design and a review of OE increased resistance of connection is not an applicable aging effect for MNGP transmission connectors. MNGP transmission connectors within the scope of license renewal are not subject to oxidation or loss of pre-load. See SLRA Section 3.6.2.2.3 for additional information.

9. Based on MNGP design and a review of OE loss of conductor strength is not an applicable aging effect for MNGP ACSR transmission conductors. MNGP ACSR transmission conductors within the scope of license renewal are not subject to loss of conductor strength due to corrosion. See SLRA Section 3.6.2.2.3 for additional information.

10. Based on MNGP design and a review of OE loss of material is not an applicable aging effect for MNGP ACSR transmission conductors. MNGP ACSR transmission conductors within the scope of license renewal are not subject to wind-induced abrasion. There are no AAC or ACAR transmission conductors within the scope of license renewal for MNGP. See SLRA Section 3.6.2.2.3 for additional information.

4.0 TIME-LIMITED AGING ANALYSES

This section presents descriptions of the TLAA and exemptions for MNGP in accordance with 10 CFR 54.3(a) and 10 CFR 54.21(c). Section 4 is divided into Sections 4.1 through 4.6. A number of supporting non-proprietary and proprietary reference documents are cited, where applicable, throughout this section.

Section 4.1 presents the summary of the results of the process to identify MNGP TLAAs. Subsequent sections describe the evaluation of each TLAA within the following categories.

- Section 4.2, *Reactor Vessel Neutron Embrittlement*
- Section 4.3, *Metal Fatigue*
- Section 4.4, *Environmental Qualification (EQ) of Electric Equipment*
- Section 4.5, *Containment Liner Plate, Metal Containments, and Penetrations Fatigue*
- Section 4.6, *Other Plant-Specific TLAA*

4.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

Pursuant to 10 CFR 54.3, time-limited aging analyses are defined as those licensee calculations and analyses that:

(1) Involve SSCs 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 CLB.

4.1.1 Time-Limited Aging Analyses Identification Process

TLAAs have been identified for MNGP using methods consistent with those provided in NUREG 2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants* (SRP-SLR) and with 10 CFR 54, *Requirements for Renewal of Operating License for Nuclear Power Plants*.

A generic list of potential TLAAs was assembled from the SRP-SLR, industry guidance, and experience including:

- NUREG-2191, *Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,* Final Report, July 2017.
- NUREG-2192, *Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants*, Final Report, July 2017.
- NEI 17-01, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,* Revision 0, December 2017.
- 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*.
- Prior SLRAs, NRC Requests for Additional Information, and NRC SERs for these applications.
- Plant-specific document reviews.

CLB and DBDs were searched to identify potential TLAAs. The document search included the following:

- Updated Safety Analysis Report (USAR)
- Technical Specifications and Bases (TS and TSB)
- Technical Requirements Manual and Bases (TRM and TRMB)

- Renewed Facility Operating License (FOL), including conditions and appendices
- MNGP LRA and associated NRC SER
- calculations and design reports referenced in the USAR, TS, TSB, TRM, TRMB and FOL
- Fire Protection Report
- Offsite Dose Calculation Manual (ODCM)
- Inservice Testing Program Plan (IST)
- Inservice Inspection (ISI) Program Plan
- Core Operating Limits Report (COLR) (Cycle 31)
- Pressure and Temperature Limits Report (PTLR)
- NRC SERs
- Docketed licensing correspondence

Each potential TLAA was reviewed against the six criteria of 10 CFR 54.3(a). Those that met all six criteria were identified as TLAAs which require evaluation for the subsequent PEO. Table 4.1-1 lists the example TLAAs provided in NUREG-2192, Tables 4.1-2 and 4.7-1, and specifies whether these have been identified as TLAAs for MNGP. Those with a "Yes" entry apply to MNGP and the SLRA section where they are evaluated is provided. Those with a "No" entry were determined to not apply to MNGP. No TLAAs were identified for the items marked "No" either because they are associated with design features not employed at MNGP or because no analyses were identified in this category that meet all six TLAA criteria. Additional plant-specific TLAA that met all six criteria are included in Table 4.1-2.

MNGP also reviewed previous SLRAs and requests for additional information to determine if a TLAA evaluated for another plant was applicable to MNGP. Any TLAA from other SLRAs deemed to be a potential TLAA for MNGP were added to Table 4.1-1 for follow-up evaluation.

Table 4.1-1

Review of Generic TLAAs Listed in NUREG-2192, Tables 4.1-2 and 4.7-1

NUREG-2192 Example TLAA	Applies to MNGP?	SLRA Section
NUREG-2192, 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 Pressure Overpressure Protection System Setpoints (PWRs Only)	No	N/A
Ductility Reduction Evaluation for Reactor Internals (B&W designed PWRs only)	No	N/A

Table 4.1-1

Review of Generic TLAAs Listed in NUREG-2192, Tables 4.1-2 and 4.7-1

NUREG-2192 Example TLAA	Applies to MNGP?	SLRA Section
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	Yes	4.3.3, 4.3.4 and 4.3.5
Metal Fatigue of Non-Class 1 Components	Yes	4.3.6
Environmentally-Assisted Fatigue	Yes	4.3.7
High Energy Line Break Analyses	No(1)	N/A
Cycle-dependent Fracture Mechanics or Flaw Evaluations	No(2)	N/A
Cycle-dependent Fatigue Waivers	Yes	4.3.2
Environmental Qualification of Electric Equipment	Yes	4.4
Concrete Containment Tendon Pre-Stress	No(3)	N/A
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes(3)	4.5
NUREG-2192, Table 4.7-1 – Examples of Potential Plant-Specific TLAA Topics (BWRs, BWRs and PWRs)		
Re-Flood Thermal Shock of the Reactor Pressure Vessel	Yes	4.2.7
Re-Flood Thermal Shock of the Core Shroud And Other Reactor Vessel Internals	Yes	4.2.8
Loss of Preload For Core Plate Rim Holddown Bolts	Yes	4.2.9
Erosion of the Main Steam Line Flow Restrictors	No(4)	N/A
Susceptibility to Irradiation-Assisted Stress Corrosion Cracking (IASCC)	Yes	4.2.10
Fatigue of Cranes (Crane Cycle Limits)	Yes	4.5.1
Fatigue of The Spent Fuel Pool Liner	No(5)	N/A
Corrosion Allowance Calculations	No(6)	N/A
Flaw Growth Due to Stress Corrosion Cracking	No(7)	N/A
Predicted Lower Limit	No(3)	N/A

Table 4.1-1

Review of Generic TLAAs Listed in NUREG-2192, Tables 4.1-2 and 4.7-1

NUREG-2192 Example TLAA	Applies to MNGP?	SLRA Section
Notes: (1) High energy line break based on fatigue cumulative usage factor is not a TLAA for MNGP, and as such is not included with metal fatigue. Break locations were not postulated based on fatigue criteria (i.e., CUF). (2) The MNGP CLB does not contain time-limited analyses for any additional fracture mechanics or flaw evaluations. (3) The MNGP containment design does not employ prestressed concrete tendons; the primary containment at MNGP consists of a steel lightbulb-shaped drywell, a steel doughnut-shaped pressure suppression chamber, and interconnecting vent pipes. (4) The MNGP CLB does not contain time-limited analyses for erosion of the main steam line flow restrictors. Aging management of the main steam line flow restrictors is performed under the MNGP One-Time Inspection (B.2.3.20) and Water Chemistry (B.2.3.2) AMPs. (5) There is no fatigue analysis for the MNGP spent fuel pool liner. (6) While time-limited instances for the MSIVs and jet pump assemblies are included in MNGP CLB documentation, these items do not meet the six criteria of 10 CFR 54.3 because they either do not perform a license renewal intended function or the specifications identify a margin to accommodate the possibility of corrosion so there is no analysis that involves a time limit. Therefore, these are not TLAAs. (7) MNGP has not used IWB-3600 methods to justify acceptability of a flaw until the end of the current term of operation. MNGP has used IWB-3600 for REC System safe end and piping manifold flaw repairs; however, these components were replaced in 1984 with materials resistant to intergranular stress corrosion cracking (IGSCC).		

4.1.2 Evaluation of MNGP Time-Limited Aging Analyses

Each subsequent part of Section 4 evaluates one or more related TLAAs. Information is provided using the following definitions:

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 SPEO, provides information associated with 80 years of operation for comparison with the information used in the TLAA that considered 60 years of operation. This evaluation will provide the basis for the disposition, which will fall into one of the three disposition categories described below.

TLAA Disposition

The disposition is classified in accordance with one or more of the acceptance criteria from 10 CFR 54.21(c)(1) specified below in 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 or more of these three methods were used to disposition each TLAA identified for MNGP. The disposition methods used are described in each TLAA evaluation section.

4.1.4 Identification and Evaluation of Exemptions

10 CFR 54.21(c)(2) states that for TLAA exemptions, a list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the PEO.

In order to identify exemptions for MNGP, a keyword search was conducted. The MNGP USAR, renewed operating license, tech specs and bases, technical requirements manual and basis, SERs and supplements, Fire Protection Plan, and NRC ADAMS database were searched. This review involved a search to identify exemptions that were granted pursuant to 10 CFR 50.12. The search criteria utilize key terms, including 10 CFR 50.12, exempt, waiver, N-415, NB-3222.4(d), relief request, life of, 60 years, and sixty years.

Exemptions related to the spent fuel dry cask storage are not included since the program is not part of the MNGP operating license. The ISFSI for spent fuel dry cask storage at MNGP is designed and licensed in accordance with 10 CFR Part 72.

MNGP specific exemptions from 10 CFR Part 50, Appendix R, and relief requests associated with the Section XI Program were reviewed. Additionally, identified exemptions were reviewed from recent license renewal applications. A review of the above and a search of docketed correspondence, the operating license, and the USAR identified fatigue exemptions for RPV components that are considered a TLAA.

4.1.5 Summary of Results

Several categories of TLAAs were identified for MNGP. The TLAAs are grouped together by affected component type and aging effect analyzed, as shown in the TLAA Summary in Table 4.1-2. The table includes a reference to the applicable section of the application that evaluates each TLAA. Section 4.1.5 evaluates exemptions to 10 CFR 50.12 in effect that are based upon TLAAs. Sections starting with Section 4.2 provide descriptions and evaluations of the TLAAs and classify their disposition.

Table 4.1-2

Summary of Results – MNGP Time-Limited Aging Analysis

TLAA Description	Disposition	SLRA Section
Identification and Evaluation of Time-Limited Aging Analyses and Exemptions		4.1
Identification of Time-Limited Aging Analysis	N/A	4.1.1
Evaluation of Time-Limited Aging Analyses	N/A	4.1.2
Acceptance Criteria	N/A	4.1.3
Summary of Results	N/A	4.1.4
Identification and Evaluation of Exemptions	N/A	4.1.5
Reactor Vessel Neutron Embrittlement		4.2
RPV Neutron Fluence	**10 CFR 54.21(c)(1)(iii)**	4.2.1.1
RVI Neutron Fluence	**10 CFR 54.21(c)(1)(iii)**	4.2.1.2
RPV Materials Upper Shelf Energy (USE) Reduction Due to Neutron Embrittlement	**10 CFR 54.21(c)(1)(ii)**	4.2.2
Adjusted Reference Temperature (ART) for RPV Materials Due to Neutron Embrittlement	**10 CFR 54.21(c)(1)(ii)**	4.2.3
RPV Thermal Limit Analysis: Operating P-T Limits	**10 CFR 54.21(c)(1)(iii)**	4.2.4
RPV Circumferential Weld Examination Relief	**10 CFR 54.21(c)(1)(iii)**	4.2.5
RPV Axial Weld Failure Probability	**10 CFR 54.21(c)(1)(ii)**	4.2.6
Reflood Thermal Shock Analysis of the RPV	**10 CFR 54.21(c)(1)(ii)**	4.2.7
Reflood Thermal Shock Analysis of the RPV Core Shroud	**10 CFR 54.21(c)(1)(ii)**	4.2.8

Table 4.1-2

Summary of Results – MNGP Time-Limited Aging Analysis

TLAA Description	Disposition	SLRA Section
Loss of Preload for Core Plate Rim Holddown Bolts	**10 CFR 54.21(c)(1)(ii)**	4.2.9
Susceptibility to IASCC	**10 CFR 54.21(c)(1)(iii)**	4.2.10
Metal Fatigue		4.3
80-Year Transient Cycle Projections	N/A	4.3.1
ASME Section III, Class 1 Fatigue Waivers	**10 CFR 54.21(c)(1)(iii)**	4.3.2
RPV Fatigue Analyses	**10 CFR 54.21(c)(1)(iii)**	4.3.3
Fatigue Analysis of RPV Internals	**10 CFR 54.21(c)(1)(i)**	4.3.4
ASME Section III, Class 1 Fatigue Analysis	**10 CFR 54.21(c)(1)(iii)**	4.3.5
ASME Section III, Class 2 and 3 and ANSI B31.1	**10 CFR 54.21(c)(1)(i)**	4.3.6
Environmentally-Assisted Fatigue	**10 CFR 54.21(c)(1)(iii)**	4.3.7
Environmental Qualification (EQ) of Electric Components	**10 CFR 54.21(c)(1)(iii)**	4.4
Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses		4.5
Fatigue Analysis of the Suppression Chamber, Vents, Downcomers, and Torus Shell	**10 CFR 54.21(c)(1)(iii)**	4.5.1
Fatigue Analysis of the Safety Relief Valve (SRV) Discharge Piping Inside the Suppression Chamber	**10 CFR 54.21(c)(1)(iii)**	4.5.2
Fatigue Analysis of Suppression Chamber External Piping and Penetrations, Including Ring Header	**10 CFR 54.21(c)(1)(iii)**	4.5.3
Drywell-to-Suppression Chamber Vent Line Bellows Fatigue Analysis	**10 CFR 54.21(c)(1)(i)**	4.5.4
Primary Containment Process Penetration Bellows Fatigue Analysis	**10 CFR 54.21(c)(1)(i)**	4.5.5
Other Plant-Specific Time-Limited Aging Analyses		4.6
Fatigue of Cranes	**10 CFR 54.21(c)(1)(ii)**	4.6.1
Fatigue Analyses of High-Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Turbine Exhaust Penetrations	**10 CFR 54.21(c)(1)(ii)**	4.6.2
Condensate Backwash Receiving Tank Fatigue Analysis	**10 CFR 54.21(c)(1)(ii)**	4.6.3

4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR Part 50, Appendices G and H. The ferritic materials of the reactor vessel are subject to embrittlement due to high energy (E >1.0 MeV) neutron exposure. Embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). Since these neutron embrittlement analyses are calculated based on plant life, they are identified as TLAA. This group of TLAA concerns the effect of irradiation embrittlement on the beltline and extended beltline regions of the MNGP reactor vessel, and how this mechanism affects analyses that provide operating limits or address regulatory requirements.

Fracture toughness (indirectly measured in foot-pounds of absorbed energy in a Charpy impact test) is temperature dependent in ferritic materials. An initial nil-ductility reference temperature (RT_{NDT}) is associated with the transition from ductile to brittle behavior and is determined for vessel materials through a combination of Charpy and drop-weight testing. Toughness increases with temperature up to a maximum value called the “upper-shelf energy,” or USE. Neutron embrittlement results in a decrease in the USE (maximum toughness) of the reactor vessel steels.

To reduce the potential for brittle fracture during reactor 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 included in the MNGP Pressure and Temperature Limits Report (PTLR). The P-T limits account for the decrease in material toughness of the reactor vessel beltline materials that are predicted to receive a cumulative neutron exposure of 1.0×10^{17} neutrons/cm^2 (n/cm^2) or more during the licensed life of the plant. Since the cumulative neutron fluence will increase during the SPEO, a review is required to determine if any additional components will exceed the cumulative neutron fluence threshold value and require evaluation for neutron embrittlement. This applies to materials in the active fuel region defined as the “beltline region” and materials that exceed the threshold of 1.0×10^{17} n/cm^2 that are outside of the beltline, referred to as the “extended beltline.”

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. P-T limit curves are generated to provide minimum temperature limits that must be achieved during operations prior to applications of specified reactor vessel pressures. The P-T limit curves are based upon the RT_{NDT} and ΔRT_{NDT} values computed for the licensed operating period along with appropriate margins.

The reactor vessel material ΔRT_{NDT} and USE values, calculated on the basis of neutron fluence, are part of the CLB and support safety determinations. Therefore, these calculations have been identified as TLAAs. A reflood thermal shock analysis for the RPV has been also identified that is based upon irradiated material properties derived using neutron fluence values as inputs. The following TLAA related to neutron embrittlement are evaluated in the SLRA sections listed below:

- Neutron Fluence Projections (4.2.1)
- Upper Shelf Energy (USE) Reduction (4.2.2)
- Adjusted Reference Temperature (ART) for RPV Materials (4.2.3)
- Operating Pressure-Temperature Limits (4.2.4)
- RPV Circumferential Weld Examination Relief (4.2.5)
- RPV Axial Weld Failure Probability (4.2.6)
- Reflood Thermal Shock Analysis of the RPV (4.2.7)
- Reflood Thermal Shock Analysis of the RPV Core Shroud (4.2.8)
- Loss of Preload for Core Plate Rim Holddown Bolts (4.2.9)
- Susceptibility to IASCC (4.2.10)

4.2.1 Neutron Fluence Projections

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter (flux) that contact the reactor vessel shell and its internal components. The fluence projections that quantify the number of neutrons that contact these surfaces have been used as inputs to the neutron embrittlement analyses that evaluate the reduction of fracture toughness aging effect resulting from neutron irradiation and is a TLAA for the MNGP 80-year SPEO.

For 80 years, corresponding to 72 EFPY, TransWare RAMA methodology has been used to develop fluence projections for RPV and internal (RVI) components that are used in evaluating TLAAs in SLRA Sections 4.2.2 through 4.2.10. The basis for acceptability of each of these fluence projection methods is described in the applicable sections below.

MNGP Power Level History

Below is a summary MNGP historical operating power levels which have been considered in developing the 80-year fluence projections:

- Original licensed operating power of 1670 MWt
- Power uprate to 1775 MWt in 1998 by Amendment 102
- Extended power uprate to 2004 MWt in December 2013 by Amendment 176
- In 2014, the reactor operating domain was expanded to include the MELLLA+ region.
- In 2014, 2015, and 2017, NRC approval was given for use of a Spent Fuel Pool criticality analysis for use of Framatome fuel licensing methods and use of ATRIUM-10XM fuel in the core, and for core operation in a power-flow range called the Extended Flow Window (EFW), which is identical to the MELLLA+ operating domain.

4.2.1.1 RPV Neutron Fluence

TLAA Description

Fluence projections have been used as inputs in the CLB RPV neutron embrittlement analyses for beltline components, including analyses of Upper Shelf Energy (USE), ART, P-T limits, axial and circumferential weld failure probability, and RPV reflood thermal shock. The previous fluence projection analyses, reported in the MNGP EPU license amendment request (Reference 4.7.1), were developed for 60 years and 54 EFPY for 2,004 MWt.

Neutron fluence values have been projected for 80 years and used as inputs in updated analysis of 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 current P-T limits expiring, as described in Section 4.2.4, consistent with the guidance provided in NUREG-2192.

Fluence was calculated for the MNGP RPV for the extended 60-year (54 EFPY) licensed operating periods using the methodology of NEDC-32983P-A, *General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations*, which was approved by the NRC in a letter dated December 9, 2013 (Reference 4.7.2). The NRC found that, in general, this methodology adheres to the guidance in RG 1.190 (Reference 4.7.3) for neutron flux evaluation. The fluence calculations were performed with the GE's Discrete Ordinates Transport code (DORT). These current fluence analyses have been identified as TLAAs that require evaluation for the SPEO.

TLAA Evaluation

The fast neutron fluence presented in this report utilizes historical reactor exposure data to the end of Cycle 30 ("EOC 30") with fluence projections to 72 EFPY of reactor operation. The reactor exposure accumulated at EOC 30 was determined to be 40.3 EFPY. Fluence projections to 72 EFPY were determined assuming the operating data for a projection Cycle 31 comprised of GE14 and ATRIUM-10XM fuel products and a projection cycle comprised of ATRIUM-11 fuel product to EOL.

The MNGP Reactor Pressure Vessel fluence evaluation for SLR was generated with the methods in compliance with RG 1.190. TransWare has benchmarked the RAMA Fluence Methodology against industry standard benchmarks and plant-specific dosimetry measurements for BWRs and PWRs. RAMA was developed by TransWare and is described in BWRVIP-114-A (Reference 4.7.4). The results of the benchmarking show that the fluence methodology implemented by TransWare is capable of predicting specimen activities with no discernable bias in the computed fluence. The combined uncertainty for the MNGP reactor pressure vessel is determined to be 11.6 percent. Based upon these results, there is no discernable bias in the computed reactor pressure vessel fluence for the period of Cycle 1 through the end of Cycle 30 for the MNGP reactor.

SLR-ISG-2021-02-Mechanical provides additional details regarding acceptable RG 1.190-adherent methodologies. The NRC staff reviewed additional qualification data in the safety evaluation approving Licensing Topical Report BWRVIP 145NP-A, *BWR Vessel Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Materials Samples Using RAMA Fluence Methodology* (Reference 4.7.5). This was one example in which an applicant justified the application of RG 1.190-adherent methods, or appropriate alternatives, to evaluate fluence in regions outside the immediate, core-adjacent area of the RPV beltline. The approach taken for MNGP is identical to that described in BWRVIP-145NP-A.

Maximum fast neutron fluence (Energy >1.0 MeV) is specifically reported for the following RPV components. Figure 4.2.1.1-1 illustrates the location of the welds, shell plates, and nozzles in the RPV.

- RPV Welds
  - The maximum fluence is reported at 0T, 1/4T, and 3/4T for the following horizontal and vertical welds in the RPV beltline and extended beltline region: VCBA-2, VCBB-3, VLAA-1, VLAA-2, VLBA-1, VLBA-2, VLCB-1, and VLCB-2.
- RPV Shell Courses
  - The maximum fluence is reported at 0T, 1/4T, and 3/4T for the following shells in the RPV extended beltline region: Shell Course 1, Shell Course 2, and Shell Course 3.
- RPV Nozzles and Extraction Paths
  - The maximum fluence is reported at 0T, 1/4T, and 3/4T for each N2 nozzle along the forging-to-base metal welds and the extraction path in the nozzle forgings.

MNGP is a BWR/3 class reactor with a core loading of 484 fuel assemblies. The fluence evaluation for this reactor uses fluence that is calculated at EOC 30 (40.3 EFPY) and an 80 reactor-year lifetime corresponding to 72 EFPY. Both historical and projected reactor operating data are used in the analyses.

The 72 EFPY fluence projections are provided in the following tables:

(1) Table 4.2.1.1-1, Maximum Fast Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 72 EFPY (n/cm^2)

(2) Table 4.2.1.1-2, Maximum Fast Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 72 EFPY (n/cm^2)

(3) Table 4.2.1.1-3, Maximum Fast Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles at 72 EFPY (n/cm^2)

(4) Table 4.2.1.1-4, RPV Extended Beltline Elevation Range

Table 4.2.1.1-1 reports the maximum fluence that is determined for the RPV horizontal and vertical welds at 72 EFPY. The maximum fluence for each weld is determined to occur at the inner surface (0T) of the RPV base metal, with the maximum fluence occurring in horizontal weld VCBA-2 with a value of 3.79 x 10^{18} n/cm^2 at 72 EFPY.

Table 4.2.1.1-2 reports the maximum fluence that is determined for each RPV shell plate at 72 EFPY. The maximum fluence for each shell plate is determined to occur at the inner surface (0T) of the RPV base metal, with the maximum fluence occurring in shell course 2 with a value of 5.94 x 10^{18} n/cm^2 at 72 EFPY.

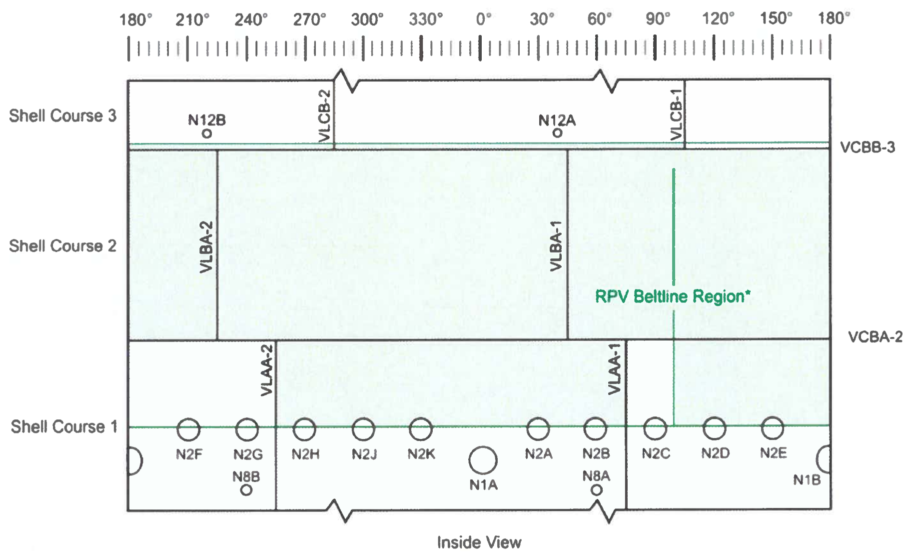
Table 4.2.1.1-3 reports the maximum fluence that is determined for the RPV nozzles at 72 EFPY. Fluence for the nozzles is presented along two paths: one along the nozzle forging-to-base-metal weld and the other along an extraction path that extends from the inside corner of the forging to the outside surface of the RPV wall. The maximum fluence occurs at the 90° weld with a value of 7.08 x 10^{17} n/cm^2 at 72 EFPY.

Table 4.2.1.1-4 reports the elevations that define the RPV extended beltline at 72 EFPY. It is shown that the RPV beltline at 72 EFPY is determined to cover 490.8 cm, or approximately 16.1 ft, of the reactor vessel wall.

The fast neutron fluence that is used in material embrittlement evaluations should be determined using an appropriate damage function (such as displacements-per-atom of iron) rather than the computed fast neutron fluence obtained from transport calculations. TransWare’s implementation of the RAMA Fluence Methodology can uniquely calculate the more accurate plant-specific fluence in the RPV wall using the displacements-per-atom attenuation method specified in RG 1.99, Revision 2. Therefore, only the plant-specific fast neutron fluence is presented in this report for the MNGP RPV horizontal (circumferential) welds, vertical (axial) welds, shell plates, and nozzles that reside in the RPV extended beltline region.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging due to fluence on the intended function will be adequately managed for the SPEO utilizing the Neutron Fluence Monitoring AMP (B.2.2.2) and the Reactor Vessel Material Surveillance AMP (B.2.3.19) in accordance with **10 CFR 54.21(c)(1)(iii)**. The exposure results are used as inputs in the neutron embrittlement TLAA evaluations in the remainder of Section 4.2.



Notes: This drawing is not to scale.
RPV beltline region is shown for 72 EFPY

Figure 4.2.1.1-1: MNGP RPV Beltline Region at 72 EFPY

Table 4.2.1.1-1 Maximum Fast Neutron Fluence for MNGP RPV Welds at 72 EFPY

Weld	Azimuth	Elevation [in (cm)][(1)]	Fast Neutron Damage Fluence (n/cm^2)		
			0T	1/4T	3/4T
Horizontal Welds					
VCBA-2	1°	234.6 (595.8)	**3.79E+18**	2.77E+18	1.25E+18
VCBB-3	88°	366.1 (930.0)	3.23E+17	2.52E+17	1.38E+17
Shell Course 1 Vertical Welds					
VLAA-1	75°	234.6 (595.8)	**2.35E+18**	1.71E+18	7.82E+17
VLAA-2	255°	234.6 (595.8)	**2.35E+18**	1.71E+18	7.82E+17
Shell Course 2 Vertical Welds					
VLBA-1	45°	296.4 (752.7)	**2.10E+18**	1.54E+18	7.10E+17
VLBA-2	225°	296.4 (752.7)	**2.10E+18**	1.54E+18	7.10E+17
Shell Course 3 Vertical Welds					
VLCB-1	105°	366.1 (930.0)	**2.12E+17**	1.66E+17	9.42E+16
VLCB-2	285°	366.1 (930.0)	**2.12E+17**	1.66E+17	9.42E+16

(1) Azimuth and elevation values are listed for the 0T location only.

Table 4.2.1.1-2 Maximum Fast Neutron Fluence for the Montello RPV Shell Plates at 72 EFPY

Shell Plate	Azimuth	Elevation [in (cm)][(1)]	Fast Neutron Damage Fluence (n/cm^2)		
			0T	1/4T	3/4T
EOC 30 (40.3 EFPY)					
Shell Course 1	1°	234.6 (595.8)	**2.13E+18**	1.55E+18	7.00E+17
Shell Course 2	1°	302.3 (767.9)	**3.33E+18**	2.43E+18	1.09E+18
Shell Course 3	88°	366.1 (930.0)	**1.60E+17**	1.25E+17	6.89E+16
72 EFPY					
Shell Course 1	1°	234.6 (595.8)	**3.79E+18**	2.77E+18	1.25E+18
Shell Course 2	1°	302.3 (767.9)	**5.94E+18**	4.35E+18	1.96E+18
Shell Course 3	88°	366.1 (930.0)	**3.23E+17**	2.52E+17	1.38E+17

(1) Azimuth and elevation values are listed for the 0T location only.

Table 4.2.1.1-3 Maximum Fast Neutron Fluence for the MNGP RPV Nozzles at 72 EFPY

Location	Azimuth	Elevation [in (cm)][(1)]	Fast Neutron Fluence at (n/cm^2)		
			0T	1/4T	3/4T
N1 Nozzle					
Weld	0°	150.0 (381.0)	**3.25E+16**	2.90E+16	2.38E+16
Extraction Path			2.05E+15	3.45E+15	9.02E+15
N2 Nozzles					
Weld	30°	186.0 (472.4)	3.25E+17	2.40E+17	1.24E+17
Extraction Path			7.48E+16	7.39E+16	7.47E+16
Weld	60°		3.26E+17	2.41E+17	1.24E+17
Extraction Path			7.51E+16	7.41E+16	7.44E+16
Weld	90°		**7.08E+17**	5.27E+17	2.61E+17
Extraction Path			1.47E+17	1.46E+17	1.48E+17

(1) Elevation values correspond to each nozzle centerline elevation.

Table 4.2.1.1-4 Extended Beltline Elevation Range

Reactor Lifetime	Lower Elevation [in (cm)]	Upper Elevation [in (cm)]	Axial Span of the RPV Beltline [in (cm)]
EOC 30 (40.3 EFPY)	194.25 (493.40)	371.48 (943.57)	177.23 (450.17)
72 EFPY	190.48 (483.81)	383.72 (974.64)	193.24 (490.83)

4.2.1.2 RVI Neutron Fluence

TLAA Description

Fast neutron fluence exposure has been used as input in analyses of MNGP reactor vessel internals components, including the core shroud, jet pump, top guide, core support plate, and in-core instrumentation tubes. In addition, fluence projections are used to determine when specified fluence threshold values may be exceeded to invoke specific aging management requirements, such as inspections. Since the fast neutron fluence exposure is time dependent, these analyses have been identified as TLAAs that require evaluation for the SPEO.

TLAA Evaluation

Fast neutron fluence was determined for selected RVI components for 80 years. While there are no regulatory requirements comparable to RG 1.190 that provide guidance for determining fast neutron fluence in RVI components, the NRC has issued a safety evaluation providing conditional approval to use the RAMA Fluence Methodology for determining fluence in BWR top guide and core shroud components under BWRVIP-145NP-A. The safety evaluation concludes that:

> *for applications such as IASCC, crack propagation rates and weldability determinations, the RAMA methodology can be used in determining fast neutron fluence values in the core shroud and top guide…for licensing actions provided that the calculational results are supported by sufficient justification that the proposed values are conservative for the intended application.*

While the safety evaluation addresses only the core shroud and top guide components, the same guidance for determining conservative fluence was applied to all RVI components evaluated.

The fast neutron fluence determined for RVI components utilized the reactor exposure to the end of Cycle 30 (EOC 30) with fluence projections to 72 EFPY. The exposure accumulated at EOC 30 was determined to be 40.3 EFPY. Fluence projections to 72 EFPY were determined assuming the operating data for projection Cycle 31 as a transition cycle and a projection cycle comprised of a full-core loading of ATRIUM-11 fuel.

Maximum fast neutron fluence (E >1.0 MeV) is specifically reported for the following RVI components:

- Core Shroud Welds
    - The maximum fluence is reported at 0T, 1/2T, and 1T for each horizontal and vertical weld in the RPV extended beltline region: H1-H6 and V1-V8.
- Jet Pumps
    - The maximum fluence is reported for the jet pump riser pipe welds: RS-1, RS-2, RS-3, RS-4, RS-5, RS-8, RS-9, RS-10, and RS-11.

  - The maximum fluence is reported for the mixer barrel, mixer adapter, mixer flare, mixer flange, diffuser collar, mixer nozzle, mixer 180° elbow, transition piece, and hold-down beam.

- Top Guide
  - The maximum fluence for the top guide cells (grid beams).
  - The maximum fluence for the top guide rim structure and supports.
- Core Support Plate and Rim Bolts
  - The maximum fluence and location is reported for the core support plate, CRGT-1 weld, and CRGT-2 weld.
  - The maximum approximated fluence and location is reported for the control rod guide tube base.
  - The maximum fluence is reported for the core support plate rim bolts and the axial profile for the maximum bolt.
- Core Spray Spargers
  - The maximum fluence is reported for the lower sparger pipe and nozzles.
- In-Core Instrumentation Tubes
  - The maximum fluence and location is reported for the in-core instrumentation tubes.

Table 4.2.1.2-1 provides fluence projections for the MNGP RVI components.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging due to fluence on the intended function will be adequately managed for the SPEO utilizing the Neutron Fluence Monitoring AMP (B.2.2.2) in accordance with **10 CFR 54.21(c)(1)(iii).**

Table 4.2.1.2-1: RVI Component Fast Neutron Fluence Projections for 72 EFPY

Component		Maximum Fast Neutron Fluence (n/cm^2)
Core Shroud Welds	Vertical	1.58E+21
	Horizontal	3.68E+21
Jet Pump Components	Maximum weld fluence (RS-3)	6.40E+20
	Mixer Barrel and Adapter	2.27E+20
	Diffuser Collar	1.10E+20
	Mixer Flare	1.46E+20
	Mixer Flange	2.32E+20
	Inlet Mixer Nozzle	3.00E+20
	Inlet Mixer 180^o Elbow	3.26E+20
Top Guide Cells		1.48E+22
Core Support Plate		1.17E+21
Core Support Plate Rim Bolt at Top Surface		1.03E+20
CRGT-1 Weld		6.05E+19
CRGT-2 Weld		3.05E+18
Bottom of Control Rod Guide Tubes (Note 1)		9.67E+13
In-Core Instrument Tubes (Note 2)		1.55E+23
In-Core Instrument Guide Tubes (Note 3)		2.46E+21

Notes:

(1) The control rod guide tube base is below the lower extended beltline elevation. Therefore, the fluence is approximated.

(2) The in-core instrumentation tube is that segment of the dry tube that resides between the fuel assemblies in the active fuel region.

(3) The in-core instrumentation guide tube is that segment of the dry tube that lies below the bottom of active fuel.

4.2.2 RPV Materials Upper Shelf Energy (USE) Reduction Due to Neutron Embrittlement

TLAA Description

Upper-shelf energy (USE) is the standard industry parameter used to indicate the maximum toughness of a material at high temperature. 10 CFR 50 Appendix G requires the predicted EOL USE for RPV materials to be at least 50 ft-lb (absorbed energy) unless an approved analysis supports a lower value. The predicted USE drop is determined in accordance with NRC RG 1.99, Revision 2 (Reference 4.7.6), using the equations in the Reactor Vessel Integrity Database Version 2.0 (RVID2) (Reference 4.7.7) that accurately model the USE decrease curves in RG 1.99. For BWRs that cannot meet the 50 ft-lb criterion, the Boiling Water Reactor Vessel and Internals Project (BWRVIP) has provided a bounding equivalent margins USE analysis (EMA) for plants in Appendix B of BWRVIP-74-A (Reference 4.7.8), which is valid for up to 54 EFPY of operation.

For materials that may fall below 50 ft-lbs USE, the EMA criteria for demonstrating equivalent margins are contained in NEDO-32205-A (Reference 4.7.9) for 40 years of operation, and in BWRVIP-74-A for plant license renewal (i.e., 60 years or 54 EFPY). The USE drop for MNGP was performed previously using a conservative bounding 1/4T fluence of 3.82 x 10^{18} n/cm^2 at 54 EFPY for the limiting vessel plates and welds in the MNGP LRA. The plant surveillance data were used to verify the measured limiting plate USE percent drop confirming that the minimum Charpy USE energy of 57.5 ft-lb exceeds the 50 ft-lb acceptance criterion and, therefore, acceptable for 60 years (54 EFPY) (Reference 4.7.10).

Since the USE value is a function of neutron fluence which is associated with a specified operating period, the MNGP USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO. The projected 80-year EFPY for MNGP is assumed to be 72 EFPY.

TLAA Evaluation

Evaluation of RPV USE reduction due to neutron embrittlement for MNGP was performed for 80 years. The MNGP RPV materials have limited unirradiated USE data available. Initial unirradiated test data are available for only one plate heat for the MNGP RPV to demonstrate a minimum 50 ft-lb USE by standard methods (Reference 4.7.11). Consequently, for beltline materials lacking initial USE data, EOL USE requirements were evaluated using the EMA methodology. Available surveillance data from the MNGP RPV surveillance programs are included in the present EMA analysis. Initial USE for the surveillance plate materials is provided in BWRVIP-199 (Reference 4.7.11) and percent copper content for the RPV beltline materials are provided in the most recent evaluation or ART. Measured USE reduction for the surveillance plate material was obtained from BWRVIP-199. USE percent reductions are predicted for all beltline materials at 72 EFPY based on RG 1.99 and compared to the bounding USE reductions acceptance criteria. The EOL USE satisfies the requirements of 10 CFR 50 Appendix G if the predicted reduction in USE values is less than the bounding percent reductions. The predicted reduction uses EMA analysis to determine if the minimum USE exceeds 50 ft-lb, or a value below these thresholds.

For beltline materials lacking initial USE data, EMA evaluations using the method and criteria for performing an EMA for BWR vessels for 72 EFPY is used. Extrapolation of the percent drop in USE from the curves in Figure 2 of RG 1.99 R2 were obtained from the equations in the NRC RVID2 database. These equations are valid for fluence values between 1 x 10^{18} n/cm^2 and 6 x 10^{19} n/cm^2. Reference 4.7.12 establishes the maximum allowable percent decrease in USE for 72 EFPY operation. For BWR/3-6 plate materials, the maximum allowable percent decrease is given in Reference 4.7.12.

Values for unirradiated (initial) USE exist only for the surveillance materials (C-2220 and weld materials) and are not available for the other beltline materials. These initial USE values, along with the updated fluence projection, are used to determine the revised USE value for 72 EFPY. For the other beltline materials lacking initial USE values, EMA is performed.

Table 4.2.2-1 shows the predicted EOL USE values for MNGP beltline materials having initial USE data, based on the RG 1.99 Position 1 method. For conservatism, the percent drop in USE for the plates are increased by 14.77 percent which is the difference in percent decrease between the measured percent USE decrease, and the RG 1.99 predicted percent USE decrease for the surveillance plate heat C2220. The projected 72 EFPY 1/4T USE value is greater than 50 ft-lbs for beltline plate heat No. C2220 materials for which initial USE data are available. Therefore, the EMA per BWRVIP-74-A is not required for these materials.

For the other beltline materials lacking initial USE data, EMA was performed to evaluate the impact of revised fluence projections and available surveillance data on EOL USE reductions. The MNGP EMA evaluations are shown in Table 4.2.2-2 through Table 4.2.2-5.

The EMA evaluations were compared against the 54 EFPY limits defined in Appendix B of BWRVIP-74-A. The percent decrease is larger due to 80-year fluence, but the USE/EMA remains within the prescribed 54 EFPY limits.

These evaluations demonstrate that EOL USE values for the MNGP beltline materials remain bounded by the EMA evaluation and remain within the limits of RG 1.99 and satisfy the margin requirements of 10 CFR 50 Appendix G for at least 72 EFPY of operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The USE analyses have been projected to the end of the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

Table 4.2.2-1: USE Assessment for 72 EFPY

	Description	ID No.	Heat No.	Filler Material	%Cu	Unirradiated USE(1) (ft-lbs)	1/4t Fluence(2) (n/cm^2)	% Drop in USE	USE @ 1/4t(3) (ft-lbs)	Requires EMA
Plates	Upper/Int Shell I-12 (Course 3)	-	C2089-1	-	0.35	EMA(4)	2.38E+17	21.53	-	YES
	Upper/Int Shell I-13 (Course 3)	-	C2613-1	-	0.35	EMA(4)	2.38E+17	21.53	-	YES
	Lower/Int Shell I-14 (Course 2)	-	C2220-1	-	0.16	86.5	4.38E+18	23.65	66.0	NO
	Lower/Int Shell I-15 (Course 2)	-	C2220-2	-	0.16	86.5	4.38E+18	23.65	66.0	NO
	Lower Shell I-16 (Course 1)	-	A0946-1	-	0.14	EMA(4)	2.80E+18	19.60	-	YES
	Lower Shell I-17 (Course 1)	-	C2193-1	-	0.17	EMA(4)	2.80E+18	22.12	-	YES
Welds	Horizontal Weld	-	-	E8018N	0.10	84.5	2.80E+18	17.79	69.5	NO
	Lower (Course 1) Axial Weld	-	-	E8018N	0.10	84.5	1.73E+18	15.90	71.1	NO
	Lower/Int (Course 2) Axial Weld)	-	-	E8018N	0.10	84.5	1.55E+18	15.50	71.4	NO
	Upper/Int (Course 3) Axial Weld	-	-	E8018N	0.10	84.5	1.56E+17	9.09	76.8	NO
Nozzles	Bounding N-2 Nozzle	-	E21VW	-	0.18	70	5.23E+17	13.62	60.5	NO

Notes:

(1) See first paragraph of TLAA Evaluation.

(2) Cu content from previous ART evaluation and 1/4t fluence values for 72 EFPY from Section 4.2.3.

(3) USE at 1/4t calculated by the following formula: $USE_{Unirradiated} x \frac{100-\%dropUSE}{100}$

(4) Unirradiated USE values were not available for all beltline materials. Equivalent margin assessment (EMA) for these heats was performed.

Table 4.2.2-2: MNGP EMA for Upper Intermediate Shell I-12 for 72 EFPY BWR/3-6 Plate

Surveillance Plate (Heat C2220) USE:
%Cu = 0.16
Capsule Fluence = 9.05E+17 n/cm^2
Measured % Decrease = 16.40 (Charpy Curves)
RG 1.99 Predicted % Decrease = 14.29 (RG 1.99, Fig. 2)
Difference in % Decrease = 14.77
Upper/Int Shell I-12 (C2089-1) USE:
%Cu = 0.35
72 EFPY Peak ID Fluence = 3.23E+17 n/cm^2
72 EFPY 1/4t Fluence = 2.38E+17 n/cm^2
RG 1.99 Predicted % Decrease = 18.76 (RG 1.99, Fig. 2)
Adjusted % Decrease = 21.53 (RG 1.99, Position 2.2)
Comparison of Limiting % Decrease Value to Limit
21.53% ≤ 23.5, as the allowable % Decrease Design Limit from BWRVIP-74-A, so vessel plates are bounded by EMA

Table 4.2.2-3: MNGP EMA for Upper Intermediate Shell I-13 for 72 EFPY BWR/3-6 Plate

Surveillance Plate (Heat C2220) USE:
%Cu = 0.16
Capsule Fluence = 9.05E+17 n/cm^2
Measured % Decrease = 16.40 (Charpy Curves)
RG 1.99 Predicted % Decrease = 14.29 (RG 1.99, Fig. 2)
Difference in % Decrease = 14.77
Upper/Int Shell I-13 (C2613-1) USE:
%Cu = 0.35
72 EFPY Peak ID Fluence = 3.23E+17 n/cm^2
72 EFPY 1/4t Fluence = 2.38E+17 n/cm^2
RG 1.99 Predicted % Decrease = 18.76 (RG 1.99, Fig. 2)
Adjusted % Decrease = 21.53 (RG 1.99, Position 2.2)
Comparison of Limiting % Decrease Value to Limit
21.53% ≤ 23.5, as the allowable % Decrease Design Limit from BWRVIP-74-A, so vessel plates are bounded by EMA

Table 4.2.2-4: MNGP EMA for Lower Shell I-16 for 72 EFPY BWR/3-6 Plate

Surveillance Plate (Heat C2220) USE:
%Cu = 0.16
Capsule Fluence = 9.05E+17 n/cm^2
Measured % Decrease = 16.40 (Charpy Curves)
RG 1.99 Predicted % Decrease = 14.29 (RG 1.99, Fig. 2)
Difference in % Decrease = 14.77
Lower Shell I-16 (A0946-1) USE:
%Cu = 0.14
72 EFPY Peak ID Fluence = 3.79E+18 n/cm^2
72 EFPY 1/4t Fluence = 2.80E+18 n/cm^2
RG 1.99 Predicted % Decrease = 17.08 (RG 1.99, Fig. 2)
Adjusted % Decrease = 19.60 (RG 1.99, Position 2.2)
Comparison of Limiting % Decrease Value to Limit
19.60% ≤ 23.5, as the allowable % Decrease Design Limit from BWRVIP-74-A, so vessel plates are bounded by EMA

Table 4.2.2-5: MNGP EMA for Lower Shell I-17 for 72 EFPY BWR/3-6 Plate

Surveillance Plate (Heat C2220) USE:
%Cu = 0.16
Capsule Fluence = 9.05E+17 n/cm^2
Measured % Decrease = 16.40 (Charpy Curves)
RG 1.99 Predicted % Decrease = 14.29 (RG 1.99, Fig. 2)
Difference in % Decrease = 14.77
Lower Shell I-17 (C2193-1) USE:
%Cu = 0.17
72 EFPY Peak ID Fluence = 3.79E+18 n/cm^2
72 EFPY 1/4t Fluence = 2.80E+18 n/cm^2
RG 1.99 Predicted % Decrease = 19.35 (RG 1.99, Fig. 2)
Adjusted % Decrease = 22.12 (RG 1.99, Position 2.2)
Comparison of Limiting % Decrease Value to Limit
22.12% ≤ 23.5, as the allowable % Decrease Design Limit from BWRVIP-74-A, so vessel plates are bounded by EMA

4.2.3 Adjusted Reference Temperature (ART) for RPV Materials Due to Neutron Embrittlement

TLAA Description

The ART of the limiting beltline or extended beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. RG 1.99 provides the methodology for determining the ART of the limiting material. The initial nil ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. RG 1.99 requires calculation of ART and Reference Temperature Shift (ΔRT_{NDT}) values. The ART values are then used to determine the local fracture toughness of the RPV wall and P-T limits, according to ASME Code, Section XI, *Non-mandatory Appendix G Evaluations*. Neutron irradiation increases the RT_{NDT} beyond its initial value.

10 CFR Part 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}) means that higher temperatures are required 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} values are a function of neutron fluence, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

TLAA Evaluation

In 2011, a calculation was developed of the ART and ΔRT_{NDT} values developed for all MNGP plates, welds and nozzles exposed to fluence levels greater than 1.0×10^{17} n/cm^2. This calculation was based on the updated fluence calculations provided at that time, including the increase in neutron flux due to EPU. The ART and ΔRT_{NDT} values were calculated at 36, 40, and 54 EFPY. The reported values for 54 EFPY are intended to be applicable through the end of MNGPs current extended operating period (i.e., 60 years).

Tables 4.2.3-1 and 4.2.3-2, below, provide the surface (0T) and 1/4T fluence and fluence factor (FF) values for MNGP at 72 EFPY and the ART calculation results for 72 EFPY.

The centerline N2 recirculation inlet nozzles in the MNGP RPV are located at an elevation of 186 inches above the bottom of the reactor vessel. At 72 EFPY the lower elevation of the 1.0×10^{17} n/cm^2 fluence threshold corresponds to an RPV elevation of 190.48 inches. However, the elevation of the uppermost blend radius of the N2 nozzle is above the lower elevation. Therefore, the N2 nozzles must also be included in the ART evaluation. Based on the boundary of the extended beltline and examination of the RPV drawing, the N2 nozzles are the only forged nozzles in the extended beltline at 72 EFPY. There are no instrument nozzles in the extended beltline at 72 EFPY.

For 72 EFPY, the bounding ART values are:

- 0T for the RPV plates and welds is 197.8 °F and for the N2 nozzles is 123.9°F.
- 1/4T for the RPV plates and welds is 182.7 °F and for the N2 nozzles is 116.6°F.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The ART analyses have been projected to the end of the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

Table 4.2.3-1 0T ART Values for MNGP RPV Components at 72 EFPY

Component No.	Heat	Lot	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	72EFPY 0T Fluence (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_i (°F)	σ_Δ (°F)	72 EFPY 0T ART (°F)
Lower Shell Plates (Course 1)												
I-16	A0946-1	N/A	0.14	0.56	98	27	1.06E+18	0.429	42.1	0	17.0	90.1
I-17	C2193-1	N/A	0.17	0.5	119	0	1.06E+18	0.429	50.8	0	17.0	107.8
Lower-Intermediate Shell Plates (Course 2)												
I-14	C2220-1	N/A	Proprietary			27	5.94E+18	0.854	153.8	0	8.5	197.8
I-15	C2220-2	N/A				27	5.94E+18	0.854	153.8	0	8.5	197.8
Upper/Int Shell Plates (Course 3)												
I-12	C2089-1	N/A	0.35	0.5	200	0	3.23E+17	0.229	45.7	0	17.0	79.7
I-13	C2613-1	N/A	0.35	0.49	198	27	3.23E+17	0.229	45.5	0	17.0	106.5
Lower Shell (Course 1) Axial Welds												
VLAA-1 & VLAA-2	-	E8018N	0.1	0.99	135	-65.6	2.35E+18	0.609	82.1	12.7	28.0	78.0
Lower-Intermediate Shell (Course 2) Axial Welds:												
VLBA-1 & VLBA-2	-	E8018N	0.1	0.99	135	-65.6	2.10E+18	0.581	78.4	12.7	28.0	74.3
Upper/Int Shell (Course 3) Axial Welds:												
VLCB-1 & VLCB-2	-	E8018N	0.1	0.99	135	-65.6	2.12E+17	0.178	24.1	12.7	12.0	-6.6
Circumferential Welds												
VCBA-2 & VCBA-3	-	E8018N	0.1	0.99	135	-65.6	3.79E+18	0.732	98.7	0	28.0	89.1
N2 Nozzle												
N2 Nozzle	E21VW	N/A	0.18	0.86	142	40	7.08E+17	0.351	49.9	0	17.0	123.9

Table 4.2.3-2 1/4T ART Values for MNGP RPV Components at 72 EFPY

Component No.	Heat	Lot	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	72EFPY 1/4T Fluence (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (°F)	72 EFPY 1/4T ART (°F)
Lower Shell Plates (Course 1)												
I-16	A0946-1	N/A	0.14	0.56	98	27	2.80E+18	0.653	64.1	0	17.0	125.1
I-17	C2193-1	N/A	0.17	0.5	119	0	2.80E+18	0.653	77.3	0	17.0	111.3
Lower-Intermediate Shell Plates (Course 2)												
I-14	C2220-1	N/A	Proprietary			27	4.38E+18	0.770	138.7	0	8.5	182.7
I-15	C2220-2	N/A				27	4.38E+18	0.770	138.7	0	8.5	182.7
Upper/Int Shell Plates (Course 3)												
I-12	C2089-1	N/A	0.35	0.5	200	0	2.38E+17	0.191	38.2	0	17.0	72.2
I-13	C2613-1	N/A	0.35	0.49	198	27	2.38E+17	0.191	37.9	0	17.0	98.9
Lower Shell (Course 1) Axial Welds												
VLAA-1 & VLAA-2	-	E8018N	0.1	0.99	135	-65.6	1.73E+18	0.535	72.2	12.7	28.0	68.1
Lower-Intermediate Shell (Course 2) Axial Welds:												
VLBA-1 & VLBA-2	-	E8018N	0.1	0.99	135	-65.6	1.55E+18	0.510	68.8	12.7	28.0	64.7
Upper/Int Shell (Course 3) Axial Welds:												
VLCB-1 & VLCB-2	-	E8018N	0.1	0.99	135	-65.6	1.56E+17	0.147	19.8	12.7	9.9	-13.5
Circumferential Welds												
VCBA-2 & VCBA-3	-	E8018N	0.1	0.99	135	-65.6	2.80E+18	0.653	88.0	0	28.0	78.4
N2 Nozzle												
N2 Nozzle	E21VW	N/A	0.18	0.86	142	40	5.23E+17	0.300	42.6	0	17.0	116.6

4.2.4 RPV Thermal Limit Analysis: Operating P-T Limits

TLAA Description

10 CFR Part 50 Appendix G requires that the RPV be maintained within established P-T limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RPV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RPV fluence effect on fracture toughness.

The currently licensed P-T limit curves are located in the Pressure-Temperature Limits Report (PTLR). The current P-T limits are based upon fluence projections that were considered to represent plant operating conditions through 54 EFPY at the EPU power level of 2,004 MWt (USAR Supplement K) Since the P-T curves are based on 54 EFPY projections for the currently approved 60-year operating term, the P-T limit curves have been identified as TLAAs requiring evaluation for the SPEO.

TLAA Evaluation

In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the SPEO need not be submitted as part of the SLRA since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits. The 10 CFR 50.90 process will ensure that the MNGP P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current period of operation.

The Pressure and Temperature Limits Report (PTLR) (Reference 4.7.13) is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, and the Over Pressure Protection System (OPPS) arming temperature for the current reactor vessel fluence period. These pressure and temperature limits are determined for each fluence period in accordance with Technical Specifications.

P-T limits are contained in the PTLR, with reporting requirements in Section 5.6.5 of the MNGP Technical Specifications. The current heatup and cooldown curves were calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the reactor vessel for 54 EFPY. The Technical Specification Limiting Condition for Operation (LCO) 3.4.9 states that the RCS pressure, temperature, heatup and cooldown rates, and Recirculation Pump starting temperature shall be limited in accordance with the limit specified in the PTLR.

For BWRs, accepting P-T limits in accordance with the criterion in 10 CFR 54.21(c)(1)(iii), Renewal Applicant Action Item in the NRC staff's SER for BWRVIP-74-A (Reference 4.7.14) are addressed:

- Action Item 9: Appendix A of BWRVIP-74-A indicates that a set of P-T curves should be developed for the heatup and cooldown operating conditions in the plant at a given EFPY in the SPEO. This means that, for this action item, MNGP has not provided updated curves but shall have a procedure for updating P-T limits in accordance with 10 CFR Part 50, Appendix G, that will cover 80 years.

Appendix C contains BWRVIP Action Items, including the above item associated with BWRVIP-74-A. Prior to exceeding 54 EFPY new P-T limit curves will be generated to cover plant operation to 72 EFPY. The P-T limit curves will be developed using NRC-approved analytical methods. The analysis of the P-T limit curves will consider locations outside of the beltline such as nozzles, penetrations, and other discontinuities to determine if more restrictive P-T limits are required than would be determined by considering only the reactor vessel beltline materials.

The P-T limit curves will be updated and a Technical Specification change request will be submitted to the NRC prior to exceeding the current 54 EFPY limit.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on the intended function(s) of the reactor vessel will be adequately managed for the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**. The Reactor Vessel Material Surveillance AMP (B.2.3.19) will ensure that P-T limits will be updated and submitted to the NRC prior to exceeding the current terms of applicability in the Technical Specifications for MNGP.

4.2.5 RPV Circumferential Weld Examination Relief

TLAA Description

BWRVIP-05P (Reference 4.7.15) provides the technical basis for the elimination of ASME Code, Section XI examination of RPV circumferential welds and the reduction of examination of RPV axial welds for BWRs. The scope and evaluation for BWRVIP-05P was limited to 40 years of plant operation.

Subsequently, BWRVIP-329-A (Reference 4.7.16) and the associated NRC SER (Reference 4.7.17) 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. BWRVIP-329-A provides criteria for applicability based on plant-specific data.

TLAA Evaluation

Plant-specific RPV dimensions and material chemistry for MNGP were evaluated for the applicability criteria in BWRVIP-329-A. This confirmed that the MNGP RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

The limiting maximum reference temperatures (RT_{MAX}) for the RPV surface (0T) and 72 EFPY was calculated using plant-specific material chemistry (copper content, nickel content, chemistry factor, and $RT_{NDT(U)}$ (referred to as initial RT_{NDT})) and neutron fluence for the MNGP RPV plates and welds. The end-of-interval (EOI) for MNGP is defined as 80 years, which is equivalent to the 72 EFPY for the neutron fluence. The 0T values were calculated for the fluence at the RPV inner surface. The EOI RT_{MAX} values for all MNGP RPV plates and welds meet the acceptability criteria for limiting plate, circumferential weld, and axial weld in BWRVIP-329-A.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the MNGP RPV meets the applicability criteria of BWRVIP-329-A. As such, on the technical basis of BWRVIP-329-A and as stated in the BWRVIP-329-A SER, MNGP is justified for request for alternative pursuant to 10 CFR 40.40(a)(z)(1) from the ASME Code, Section XI examinations for RPV circumferential weld for up to 80 years of plant operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The reactor vessel circumferential weld failure probability analysis has been projected through the SPEO. Relief from inspection of circumferential welds during the SPEO will be requested through a reapplication under the 10 CFR 50.55a process in accordance with **10 CFR 54.21(c)(1)(iii)**.

4.2.6 RPV Axial Weld Failure Probability

TLAA Description

BWRVIP-05P provides the technical basis for the elimination of ASME Code, Section XI examination of RPV circumferential welds and the reduction of examination of RPV axial welds for BWRs. The scope and evaluation for BWRVIP-05P was limited to 40 years of plant operation.

Subsequently, BWRVIP-329-A 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. BWRVIP-329-A provides criteria for applicability based on plant-specific data.

TLAA Evaluation

Plant-specific RPV dimensions and material chemistry for MNGP were evaluated for the applicability criteria in BWRVIP-329-A. This confirmed that the MNGP RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

The limiting maximum reference temperatures (RT_{MAX}) for the RPV surface (0T) and 72 EFPY was calculated using plant-specific material chemistry (copper content, nickel content, chemistry factor, and $RT_{NDT(U)}$ (referred to as initial RT_{NDT})) and neutron fluence for the MNGP RPV plates and welds. The EOI for MNGP is defined as 80 years, which is equivalent to the 72 EFPY for the neutron fluence. The 0T values were calculated for the fluence at the RPV inner surface. The EOI RT_{MAX} values for all MNGP RPV plates and welds meet the acceptability criteria for limiting plate, circumferential weld, and axial weld in BWRVIP-329-A.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the MNGP RPV meets the applicability criteria of BWRVIP-329-A. As such, on the technical basis of BWRVIP-329-A and as stated in the BWRVIP-329-A SER, MNGP is justified for acceptable embrittlement of RPV axial welds for up to 80 years of plant operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The reactor vessel axial weld failure probability analyses have been satisfactorily projected through the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

4.2.7 Reflood Thermal Shock Analysis of the RPV

TLAA Description

10 CFR 50 Appendix A, *General Design Criterion (GDC) 31* requires that the reactor coolant pressure boundary of a light water reactor be designed such that it possesses adequate margin against non-ductile failure for all postulated conditions.

For General Electric (GE) designed BWRs, this requirement has historically been demonstrated through development of P-T Limit Curves (4.2.4) and reference to generic analyses such as those documented in References 4.7.18 and 4.7.19 which address the limiting Loss of Coolant Accident (LOCA) event. The acceptance criterion used in these analyses is that the crack driving force for postulated flaws in the RPV, K_I, is less than the applicable material resistance to fracture, K_{IC}.

The analysis performed to demonstrate adequate margin against non-ductile failure for the Emergency and Faulted conditions (Service Level C/D) must be updated for operation up to 80 years. The analysis performed to address service level C/D conditions is often referred to as the RPV reflood thermal shock analysis.

The MNGP USAR discusses RPV reflood thermal shock in USAR Section K3.1 in response to NRC 10 CFR 54.3(a). The MNGP USAR cites Reference 4.7.18, which concludes that no failure of the RPV due to brittle fracture from a design basis LOCA followed by a Low Pressure Coolant Injection (LPCI) will occur.

The thermal shock analysis documented in GE Report No. NEDO-10029 assumed a design basis LOCA followed by a LPCI, accounting for the full effects of neutron embrittlement at the end of 40 years. The analysis showed that the total maximum vessel irradiation (E >1 MeV) at the mid-core inside of the vessel would be 2.4 x 10^{17} n/cm^2, which was considered to be below the threshold level of any nil-ductility temperature shift for the RPV material. As a result, it was concluded that the irradiation effects on all locations of the RPV could be ignored. However, this analysis only bounded 40 years of operation.

The original analysis in GE Report No. NEDO-10029 was subsequently superseded by an analysis for BWR-6 vessels by Ranganath (Reference 4.7.18). The more recent analysis is applicable to the MNGP RPV because it evaluates the bounding LOCA event, a main steam line break, for a BWR vessel design that is similar to the MNGP vessel.

The evaluations documented in References 4.7.18 and 4.7.19 addressed the RPV shell and N2 nozzle.

Nozzles with fluence below 1.0 x 10^{17} n/cm^2 (E >1 MeV) do not require evaluation for the effects of neutron embrittlement (including effects on K_{IC}, fracture toughness). Fluences above 1.0 x 10^{17} would require additional analyses to account for the effects of neutron embrittlement.

Based on the foregoing, reflood thermal shock of the RPV forms a part of the CLB for MNGP. Therefore, since this issue is included in the USAR, with specific reference to the Ranganath paper, RPV Thermal Shock Reflood has been re-evaluated in this calculation as a TLAA for 80 years of operation.

TLAA Evaluation

The analysis documented in GE Report No. NEDO-10029 (Reference 4.7.19) address the concern for brittle fracture of the RPV due to reflood following a postulated LOCA. The analysis contained in GE Report No. NEDO-10029 has been accepted by the NRC in the licensing basis for various BWR plants. The following evaluation provides the technical basis for the adequacy of this issue as a potential TLAA for SLR, defined as 80 years or 72 EFPY.

The objective of the analyses for SLR is to demonstrate that the beltline materials in the MNGP RPV possess sufficient margin against non-ductile failure following the design basis LOCA as required by 10 CFR 50 GDC #31 through the end of the SPEO, identified as 72 EFPY.

For all beltline materials, a bounding evaluation was performed in which the limiting stresses and material properties for the MNGP RPV were used. The beltline shells (plates and welds) and the beltline nozzles were considered separately. To be consistent with previous analyses, RPV integrity is assured by fracture mechanics analyses of the limiting vessel locations to show no crack initiation would occur under these LOCA transient conditions for the SPEO. The limiting 0T ART for beltline plates and welds at 72 EFPY, corresponding to ISP plate heat number C2220-2 (present in the lower and intermediate shell) is 197.8°F (Table 4.2.3-1).

Crack driving force, $K_{Iapplied}$, during the transient is evaluated using References 4.7.18 and 4.7.19 and compared to the allowable Mode I, plane strain, static initiation fracture toughness (K_{Ic}) to demonstrate flaw stability. K_{Ic} is calculated using ASME Section XI, Nonmandatory Appendix A (Reference 4.7.20) and using the through-wall temperature distribution applicable to the limiting time steps identified in References 4.7.18 and 4.7.19. The applied loadings from the design calculations in References 4.7.18 and 4.7.19 are compared to the material resistance to cracking determined for the limiting beltline material in MNGP at 72 EFPY.

<u>Main Steam Line Break:</u>

The main steam line break LOCA was evaluated. Results of this analysis are summarized in Table 4.2.7-1. The maximum $K_{Iapplied}$ in the vessel at any time during the transient is 105 ksi√in, according to Reference 4.7.18. The LRA SER for MNGP (NUREG-1865) cites a value of 103 ksi√in. The present analysis utilizes the 105 ksi√in value, which is more conservative than the 103 ksi√in value. Therefore, K_{Ic} does not exceed $K_{Iapplied}$ by any margin of 1.35 (Table 4.2.7-1). These results demonstrate that a postulated flaw in the vessel would be stable with respect to nonductile fracture following a main steam line rupture.

PIPE-TS2 Analysis:

For the thermal stress evaluation, the Computer Program PIPE-TS2 was used to compute thermal stresses in two axisymmetric cylindrical models:

(1) one model using the BWR-6 vessel dimensions from Reference 4.7.18, and

(2) one model for the MNGP RPV.

PIPE-TS2 is a Nuclear QA approved code that computes thermal transient stresses in a cylindrical geometry using closed-form theory for thermal stresses in cylinders. The applicability of the results can be evaluated accordingly for application to the MNGP RPV.

The critical location for the fracture mechanics analysis is at 1/4T. The peak stress intensity factor, K, at 1/4T has a value of approximately 100 ksi√in. A maximum K_I of 105 ksi√in was utilized per Section XI IWB-3612. The acceptability of this K on a plant-specific basis for MNGP can be determined by considering a revised allowable fracture toughness applicable to the MNGP vessel for 72 EFPY. Based on a 0T ART of 197.8°F, the fracture toughness K_{IC} of 174.4°F is above the upper shelf value of 200 ksi√in.

The bounding stress intensity factor, K, for MNGP of 105 ksi√in is less than the available fracture toughness of 200 ksi√in after 72 EFPY, which provides an acceptable result for reshock of the vessel reflood from a main steam line break.

Analysis of Beltline Nozzles:

A plant-specific 3-dimensional (3-D) FEA transient thermal stress analysis for the MNGP N2 nozzle was performed. To understand the effect of the LOCA on the nozzle, the stress intensity factor must be assessed for the nozzle and compare it to the material K_{IC} as the criterion for unstable brittle fracture.

During a LOCA event, pressure quickly drops, removing pressure stress intensity factors so only thermal stress intensity factors need to be considered. Through-wall stress distributions were modeled. The maximum stress intensity factor from the nozzle evaluation and transient is 13.7 ksi√in. The limiting ART of the N2 nozzle is 123.9°F per Table 4.2.3-1. The conservative value for temperature at the surface from the Ranganath paper (Reference 4.7.18) is 280°F; based on this there is a margin of 10.32 applied to the nozzle per ASME Code limits, as shown in Table 4.2.7-2.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

All beltline materials in the MNGP RPV are shown to satisfy the acceptance criteria of no crack initiation for postulated flaw sizes less than or equal to the flaw sizes acceptable, without evaluation, in ASME XI IWB-3500 and considering operation through the end of the SPEO, 72 EFPY. These analyses confirm that adequate margin against non-ductile failure of the MNGP RPV and the N2 nozzle is maintained for the design basis LOCA transients through the end of the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

Table 4.2.7-1: Crack Stability Analysis for Beltline Shells during Main Steam Line Break

Minimum vessel temperature at 1/4T (°F)	395.4
Limiting ART at 0T at 72 EFPY (°F)	197.8
T - ART (°F)	197.6
K_{Ic} (ksi√in)	200
Allowable K Value ($K_{Ic}/\sqrt{2}$) (from ASME Code for √2 factor)	141
Max $K_{Iapplied}$ at any time (ksi√in)	105
Margin, $K_{Ic}/\sqrt{2}/K_{Iapplied}$	1.35

Table 4.2.7-2: Crack Stability Analysis for N2 Nozzle during Main Steam Line Break

Minimum vessel temperature at 1/4T (°F)	280
Limiting ART at 0T at 72 EFPY (°F)	123.9
T - ART (°F)	197.6
K_{Ic} (ksi√in)	200
Allowable K Value ($K_{Ic}/\sqrt{2}$) (from ASME Code for √2 factor)	141
Max $K_{Iapplied}$ at any time (ksi√in) from FEA	13.7
Margin, $K_{Ic}/\sqrt{2}/K_{Iapplied}$	10.32

4.2.8 Reflood Thermal Shock Analysis of the RPV Core Shroud

TLAA Description

Stainless steel exposed to high neutron fluence experiences an increase in yield and ultimate strength as well as a decrease in ductility as measured by the changes in the percent elongation in tensile tests. One way of assessing the effect of thermal shock is to compare the maximum strain during the reflood transient with the percent total elongation of the irradiated stainless steel. This TLAA requires confirmation that the maximum strain during reflooding is below the percent elongation of the irradiated material.

The analysis proposed for assessment of the RPV Core Shroud thermal shock has been evaluated and accepted by the NRC in the SER for License Renewal. The assessment utilizes a transient for a thermal shock event to provide a strain level based on the thermal expansion coefficient of the core shroud material, and the value provided in the LRA is applicable up to a fluence of 8 x 10^{21} n/cm^2 (E >1 MeV). The reference for this threshold has been updated to BWRVIP-66 (Reference 4.7.21).

Since this analysis was identified as a TLAA for the initial LR project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the SPEO.

TLAA Evaluation

As described in the MNGP LRA, the RPV core shroud was previously evaluated for a LPCI reflood thermal shock transient considering the embrittlement effects of 60-year exposure (54 EFPY). The core shroud receives the maximum irradiation on the inside surface opposite the midpoint of the fuel centerline. The total integrated neutron exposure at end-of-life at the inside surface of the shroud for 60 years is anticipated to be 3.84×10^{21} n/cm^2 (E >1 MeV).

The maximum thermal shock stress in this region is equivalent to 0.57 percent strain (Reference 4.7.22). This strain range of 0.57 percent was calculated at the midpoint of the shroud, the zone of highest neutron irradiation. The calculated strain range of 0.57 percent represents a considerable margin of safety relative to measured values of percent elongation for annealed Type 304 stainless steel irradiated to 8×10^{21} n/cm^2 (E >1 MeV).

The measured value of percent elongation for stainless steel weld metal is 4 percent for a temperature of 297°C (567°F) with a neutron fluence of 8×10^{21} n/cm^2 (E >1 MeV), while the average value of base metal at 290°C (554°F) is 20 percent (Reference 4.7.21). Therefore, thermal shock effects on the shroud at the point of highest irradiation level will not jeopardize the proper functioning of the shroud following the DBA. The reflood strain does not pose any concern during the current licensed operating period (PEO).

The fluence for the most irradiated point on the core shroud was calculated to be 5.68×10^{21} n/cm^2 (E >1 MeV) for 80 years. This can be compared to the test data for control blade handles at 8×10^{21} n/cm^2 (E >1 MeV) described in BWRVIP-66. The lowest measured value of percent elongation for stainless steel weld metal is 4 percent for a temperature of 297°C (567°F) with a neutron fluence of 8×10^{21} n/cm^2 (E >1 MeV), while the average value of base metal at 290°C (554°F) is 20 percent (Reference 4.7.21).

Since the most irradiated point on the core shroud for 80 years of operation is calculated to be 5.68×10^{21} n/cm^2 (E >1 MeV), below the 8×10^{21} n/cm^2 fluence threshold for which elongation test data are available, the measured value of elongation bounds the calculated thermal shock strain amplitude of 0.57 percent. The calculated thermal shock strain at the most irradiated location is acceptable considering the loss of ductility effects for an 80-year operating period.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The RPV Core Shroud will maintain sufficient ductility for 80 years of operation for low-pressure coolant injection event, even with inclusion of neutron irradiation loss of ductility effects. No further analyses or disposition is required through the end of the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

4.2.9 Loss of Preload for Core Plate Rim Holddown Bolts

TLAA Description

Stainless steel fasteners require preload to maintain stable and tight fastening of disparate components. While in-service, these fasteners can experience a stress relaxation whereby the pre-load on the fastened connection gradually decreases. Eventually, a loss of preload can induce vibrations, space between components, and eventual failure from disconnection. The loosening of these fasteners is often an unaccounted consideration of the design process, although redundancy in fastener systems helps reduce degrees of freedom for potential degradation and movement.

The fasteners for BWR core plate holddown bolts are constructed from B8 (Stainless Steel Type 304 in the solution annealed condition) (Reference 4.7.23). Two main mechanisms that affect stress relaxation are thermally-induced stress relaxation and irradiation-induced stress relaxation. Stress relaxation is similar to creep. In creep mechanisms, a constant stress gradually increases the strain of a component, while in stress relaxation, a constant strain gradually reduces the preloaded stress.

As documented in the MNGP initial LRA, Section 4.8, the core plate rim holddown bolts were evaluated for stress relaxation considering the effects of neutron fluence to affect loss of pre-load of the bolts. This item is a TLAA because it is part of the CLB, supports a safety determination, and is based on the calculated lifetime neutron fluence.

TLAA Evaluation

Stress relaxation reaches saturation in short-term tests because of elastic strain and microplastic strain are the main contributors to the total time-dependent strain, and secondary creep is insignificant in these tests for relatively low temperatures (less than 741°F).

The contribution from thermally-induced stress relaxation remains constant and may saturate over time. The evaluation performed for MNGPs initial LR includes thermally-induced stress relaxation (per NRC guidance).

Generic assessment can be performed regarding stress relaxation of fasteners relative to retained preload in operation. The BWRVIP conducted thorough bounding analyses to justify the elimination of core plate bolt examinations. Because of the inaccessibility of these components, inspection is often difficult for applicants to pursue. Guidance on the elimination of these inspections and the management of aging of these components is contained within BWRVIP-25, Revision 1-A (Reference 4.7.24).

An assessment was performed to confirm that the MNGP Core Plate Bolts can have inspections waived and have their age-related degradation managed for the SPEO for 72 EFPY. This evaluation concluded that the criteria of Appendix I of BWRVIP-25, Revision 1-A to justify the elimination of core plate bolt inspections at MNGP are satisfied. Therefore, elimination of core plate bolt inspections at MNGP for the SPEO is justified.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The loss of preload for core plate rim holddown bolts have been satisfactorily projected through the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

4.2.10 Susceptibility to IASCC

TLAA Description

The occurrence of irradiation assisted stress corrosion cracking (IASCC) requires the combined presence of an aggressive environment, a susceptible material, and a tensile stress. The environment at the top guide assembly location is highly oxidizing in all BWRs because the most oxidizing reactor water is that exiting the core and occupying the upper shroud regions. Neutron fluence can have a significant effect on those components located in high flux regions like the top guide assembly. A threshold fluence level for IASCC of 5.0 x 10^{20} n/cm^2 (E >1 MeV) is used for applicability of IASCC in BWRVIP-315, *Reactor Internals Aging Management Evaluation for Extended Operations* (Reference 4.7.25). BWRVIP guidance addresses IASCC through periodic inspection requirements for components using techniques capable of detecting cracking due to SCC and flaw tolerance guidance that considers the effect of neutron fluence on material properties and SCC growth rates.

Section 4.4 of MNGPs initial LRA presents a fluence threshold value of 5.0 x 10^{20} n/cm^2 beyond which IASCC and embrittlement may occur in BWR vessel internal components. The evaluation in the MNGP LRA identified the top guide, core shroud, and incore instrumentation dry tubes and guide tubes as being susceptible to IASCC for 60 years of operation and concluded that aging management is required through the first PEO. Since this analysis presented in Section 4.4 of the initial MNGP LRA was performed for 60 years, this analysis has been identified as a TLAA that requires evaluation for the SPEO.

TLAA Evaluation

BWRVIP-315, *Reactor Internals Aging Management Evaluation for Extended Operations* evaluated RVI components for various aging mechanisms including IASCC. Table C-1 of BWRVIP-315 identifies the components subjected to further evaluation for Item 3.1.2.2.12 (IASCC) and the corresponding BWRVIP assessment. The following components have plausible IASCC for a BWR during SPEO that would be managed by existing guidance with clarification specific to the aging mechanism of IASCC:

- Control rod guide tube (CRGT) Assembly
- Jet Pump Riser, Riser Brace, Inlet and Mixer
- Core Shroud Beltline Cylinder
- LPCI Coupling
- Top Guide

For MNGP, the BWR-3 design does not include a LPCI coupling so this component does not apply. The projected fluence values for the remaining components are summarized in Table 4.2.10-1.

CRGT Assembly

The maximum fluence value projected for the MNGP CRGT assembly is projected to be below the threshold of 5.0 x 10^{20} n/cm^2 before the end of the SPEO. The maximum projected fluence is at the CRGT-1 weld, reaching 6.05 x 10^{19} n/cm^2 (Table 4.2.1.2-1).

Jet Pump Assemblies

The maximum fluence projected for the MNGP jet pump components are projected to exceed the threshold of 5.0 x 10^{20} n/cm^2 before the end of the SPEO (Table 4.2.1.2-1). Therefore, the jet pump assemblies will be inspected periodically for cracking and loss of fracture toughness (embrittlement) during the SPEO in accordance with the BWR Vessel Internals AMP (B.2.3.7).

Section 4.3.8 of BWRVIP-315 discusses jet pump assemblies. As stated in table C-1 of BWRVIP-315, BWRVIP-41 Revision 4-A is adequate to manage cracking due to IASCC. For periodic jet pump assembly inspections, the MNGP BWR Vessel Internals AMP (B.2.3.7) utilizes the recommendations provided in BWRVIP-41 "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines" (Reference 4.7.26).

Core Shroud and Top Guide

Fluence values for the MNGP core shroud and top guide are projected to exceed the threshold of 5.0 x 10^{20} n/cm^2 before the end of the SPEO (Table 4.2.1.2-1). Therefore, the core shroud and top guide will be inspected periodically for cracking and loss of fracture toughness (embrittlement) during the SPEO in accordance with the BWR Vessel Internals AMP (B.2.3.7).

Section 4.2.3 of BWRVIP-315 discusses the management of cracking due to IASCC. For periodic core shroud inspections, the MNGP BWR Vessel Internals AMP (B.2.3.7) utilizes the recommendations provided in BWRVIP-76-R1A "BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines" (Reference 4.7.27). For periodic top guide inspections, the MNGP BWR Vessel Internals AMP (B.2.3.7) utilizes the recommendations provided in BWRVIP-26-A "BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines" (Reference 4.7.28) and BWRVIP-183-A "BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines" (Reference 4.7.29).

The aging effect of IASCC on the core shroud, top guide, and jet assembly components will be managed in the SPEO in accordance with the MNGP BWR Vessel Internals AMP (B.2.3.7).

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

Aging effects of IASCC and embrittlement on the top guide, core shroud, and jet assembly components will be managed by the BWR Vessel Internals (B.2.3.7) AMP through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.2.10-1: Projected Fluence for 72 EFPY for the Associated Components

Components	Maximum Fast Neutron Fluence (n/cm^2) 72 EFPY
Core Shroud Welds	3.68E+21
Top Guide Cells	1.48E+22
Top Guide Rim and Supports	9.81E+20
CRGT assembly	6.05E+19*
Jet Pump Components	6.40 E+20
Core Support Plate	1.17 E+21

*CRGT-1 weld value used for the CRGT assembly. According to Table 4.6 of BWRVIP-315, IASCC is applicable for relevant locations located at the upper end of the CRGT assembly. This includes only the uppermost CRGT welds (CRGT-1, potentially CRGT-2) and the fuel alignment pin weld (FS/GT-ARPIN-1). CRD housings, being below the bottom of the CRGT, experience negligible neutron fluence.

4.3 METAL FATIGUE

Fatigue analyses are required for components designed to ASME Code, Section III, Class 1. Also, certain other codes such as ASME Code, Section III, Class 2 and 3, American National Standards Institute (ANSI) B31.1, *Power Piping*, and ASME Section VIII, *Rules for Construction of Pressure Vessels*, Fatigue analyses are required for components designed to ASME Code, Section III, Class 1. Also, certain other codes such as ASME Code, Section III, Class 2 and 3, ANSI B31.1, *Power Piping*, and ASME Section VIII, *Rules for Construction of Pressure Vessels*, Division 2, may require a fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. NUREG-2192 also provides examples of components likely to have fatigue TLAA within the CLB that would require evaluation for the SPEO. Searches were performed to identify these and any other potential fatigue TLAAs within the current licensing bases for MNGP. Each of the potential TLAAs were evaluated against the six elements of the TLAA definition specified in 10 CFR 54.3. Those that were identified as fatigue TLAAs are evaluated using 80-year transient cycle and cumulative usage projections, summarized in the following subsections:

- 80-Year Transient Cycle Projections (Section 4.3.1)
- ASME Section III, Class 1 Fatigue Waivers (Section 4.3.2)
- RPV Fatigue Analyses (Section 4.3.3)
- Fatigue Analysis of RPV Internals (Section 4.3.4)
- ASME Section III, Class 1 Fatigue Analysis (Section 4.3.5)
- ASME Section III, Class 2 and 3 and ANSI B31.1 (Section 4.3.6)
- Environmentally-Assisted Fatigue (Section 4.3.7)

4.3.1 <u>80-Year Transient Cycle Projections</u>

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. The existing fatigue analyses are based upon the number of transient cycles postulated to bound 60 years of service.

Projections of the transient cycles through the SPEO were developed to determine whether the existing analyses remain valid for 80 years. These transient cycles and projections are documented in Table 4.3.1-1.

A review of Fatigue Monitoring (B.2.2.1) program data was performed to trend the number of cumulative transient cycles for each transient type that occurred at MNGP up to May 31, 2021. Linear cycle projections are calculated based on cycles that have been recorded during the most recent 10 years of plant operation. This period provides a sufficient timeframe to calculate cycle accumulation rates that provide reasonable assurance they are representative of future cycle accumulation rates. This is particularly true since the timeframe is entirely within the PEO following expiration of the original license for MNGP.

The MNGP transient cycles listed in the LRA for MNGP with USAR cycle limits are:

- Bolt Up / Unbolt 120 cycles
- Startup / Shutdown @ 100˚F/hr 289 cycles

• Scrams	270 cycles
• Design Hydrostatic Test @ 1250 psig	130 cycles
• Reactor Overpressure @ 1375 psig	1 cycle
• Hydrostatic Test to 1560 psig	3 cycles
• Rapid Blowdown	1 cycle
• Liquid Poison Flow @ 80˚F	10 cycles
• Feedwater Heater Bypass	70 cycles
• Loss of Feedwater Heater	10 cycles
• Loss of Feedwater Pumps	30 cycles
• Improper Start of Shutdown Recirc Loop	10 cycles

Turbine Roll is included with Startup with the larger of the two being used for the total count in each report. Reduction to Zero Power, Hot Standby, Hot Shutdown to Cold Shutdown are generally not counted, but would be included with Startup / Shutdown.

Fatigue Monitoring (B.2.2.1) program data does not list the following transients from the USAR list:

• Reactor Overpressure @ 1375 psig	1 cycle
• Hydrostatic Test to 1560 psig	3 cycles
• Rapid Blowdown	1 cycle
• Liquid Poison Flow @ 80˚F	10 cycles
• Operating Basis Earthquake (OBE) events	50 cycles
• Safety/Relief Valve Actuations	934 cycles

With the exception of the Hydrostatic Test to 1560 psig which is performed prior to plant operation (2 events were listed in the LRA) and Safety/Relieve Valve Actuations (506 events were listed in the LRA), none of these events has occurred to date. Other than OBE and S/RV actuations, the above listed transients are typically classified as Emergency events and are not expected to occur during the remaining operating life of MNGP so zero events are projected for 80 years of operation. For the OBE event, 1 cycle is projected to ensure that, in the unlikely event it occurs it will have been accounted for.

Although no cycles occurred during the 10 year period evaluated and none are projected to occur for the Loss of Feedwater Heater, Sudden Start, Improper Start of Shutdown Recirc Loop, Hot Standby with Drain Shutoff and Pump Restart, Core Spray Injection, and Operating Basis Earthquake, one cycle is added for conservatism.

No cycles have occurred during the 10 year period for Loss of Feedwater Pumps, but 10 percent of design cycles are added for conservatism. Adding a cycle for the Hydrostatic Test to 1560 psig was deemed inappropriate considering the fluence accumulated to date by the RPV and associated embrittlement concerns. Similarly, a cycle is not added for Reactor Overpressure at 1375 psig, Rapid Blowdown and Liquid

Poison Flow at 80˚F events because they have not occurred to date and are typically classified as Emergency events.

A summary of the projections is provided in Table 4.3.1-1. This illustrates that significant margin remains at 80 years of operation to the USAR cycle limits.

Table 4.3.1-1: 80-Year Transient Cycle Projections

Cycle Description	USAR 4.2-1 Cycle Limits	Total Cycles as of May 31, 2021	SLRA Cycles (Projected to 80 Years)	% of USAR Cycles
Bolt Up / Unbolt	120	39	59	49%
Startup /Shutdown @ 100F/hr. (**Note 2**)	289	153	203	70%
Scram (**Note 3**)	270	135	165	61%
Design Hydro Test @ 1250 psig	130	62	82	63%
Reactor Overpressure @ 1375 psig	1	0	0	0%
Hydrostatic Test to 1560 psig	3	2	2	67%
Rapid Blowdown	1	0	0	0%
Liquid Poison Flow @80F	10	0	0	0%
Feedwater Heater Bypass	70	1	4	6%
Loss of Feedwater Heater	10	0	1	10%
Loss of Feedwater Pumps	30	15	18	60%
Improper Start of Shutdown Recirc Loop (**Note 2**)	10	5	6	60%
Sudden Start	**(Note 1)**	0	1	N/A
Hot Standby with Drain Shutoff	**(Note 1)**	0	1	N/A
Core Spray Injection	**(Note 1)**	0	1	N/A
Operating Basis Earthquake (OBE)	**(Note 1)**	0	1	N/A
Safety/Relief Valve Lifts	**(Note 4)**	619	699	75%

Notes:

(1) These transient events are not included in the USAR listed transient cycles.

(2) Accumulation rate assumed in the 60-year projection is higher than actual accumulation with the latest cycle counts as of May 2021. Accumulation rate calculated for 80-years results in accumulated cycles less than those originally projected to 60 years.

(3) 15 scrams were identified in Fatigue Monitoring data from 2011 to 2021. This accumulation rate is smaller than what was calculated for 60 years and results in total cycles projected to 80 years equal to that originally projected to 60 years.

(4) Although this transient is not included in the USAR listed transient cycles, the number of design cycles (934) is provided in the MNGP LRA.

4.3.2 ASME Section III, Class 1 Fatigue Waivers

TLAA Description

Original components of the MNGP RPV were designed to the ASME Boiler and Pressure Vessel Code, 1965 Edition with Addenda through Summer 1966. The in-core detector assembly was designed to the 1971 Edition with Addenda through Summer 1973. Specific editions are not given for the IRM/SRM (intermediate range monitor/source range monitor) dry tube or the power range detector, but the paragraph numbering indicates that these were designed to the 1971 Edition or later.

The design stress reports for the MNGP RPV include fatigue waivers that determined that some RPV components did not require explicit fatigue analyses because the criteria from ASME Section III, Paragraph N-415.1 or NB-3222.4(d) were satisfied (USAR, Appendix H). The ASME Code Section III rules for performing fatigue waiver evaluations for structural components are analogous to those in the Code for performing fatigue waiver evaluations of mechanical components. ASME Code Paragraph N-415.1 or NB-3222.4(d) "Analysis for Cyclic Operations, Vessels Not Requiring Analysis for Cyclic Operation," provides for a waiver from fatigue analysis when certain cyclic loading criteria are met. N-415.1 was renumbered to NB-3222.4(d) in the 1971 ASME Code editions and later, but were otherwise unchanged.

The RPV components identified with fatigue waiver evaluations are:

- Main closure flange
- Head cooling spray and instrumentation nozzles
- Vent nozzle
- Instrumentation nozzles
- Jet pump instrumentation nozzles
- IRM/SRM dry tube
- Power range detector assembly
- In-core detector assembly

Since the ASME Section III, Paragraph N-415.1 and NB-3222.4(d) fatigue waiver criteria require postulated cycle input for the intended operating life of the plant, these fatigue waiver evaluations are TLAAs and have been reevaluated for SPEO using the 80-year projected number of transients in Table 4.3.1-1.

TLAA Evaluation

The fatigue waivers were reevaluated for SPEO in accordance with the applicable ASME Section III, Paragraph N-415.1 criteria. Pressure and temperature ranges were adjusted for rerate and EPU operating conditions. Fatigue exemption requirements require 6 conditions be met from N-415.1 or NB-3222.4(d). The reevaluations relied on projected transients and material properties, and have requirements related to:

(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 materials, and
(6) Mechanical loads.

Table 4.3.2-1 shows numbers of cycles used in the original exemption analyses, as well as 80-year projected cycles. Values for moduli of elasticity and coefficients of thermal expansion for each material were used from the ASME Boiler and Pressure Vessel Code, Section III from the editions and addenda listed above as well as the 1977 Edition with Addenda through Winter 1978.

All components reviewed in this reevaluation were found acceptable regarding fatigue usage for 80 years, including effects of rerate and EPU. The ASME Section III Class 1 fatigue waiver acceptance criterion continues to be satisfied based on 80-year projected transient cycles through the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The ASME Code, Section III, Class 1 component fatigue waivers will be managed by the Fatigue Monitoring (B.2.2.1) AMP through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**. The Fatigue Monitoring (B.2.2.1) AMP will monitor the transient cycles which are the inputs to the fatigue waiver reevaluations and require action prior to exceeding design limits that would invalidate their conclusions.

Table 4.3.2-1: Transients and Number of Cycles

	Original cycles				
Transient	**Main Closure Flanges (MCF)**	**In-core detector assembly**	**IRM/SRM dry tube**	**Power range detector assembly**	**80-year cycles**
Startup/shutdown	120	15	120	120	203
Leak test	(1)(2)	(2)	360	360	(1)
Scram	200	30	180	280	165
Design hydro test (1250 psig)	130	17	50	130	82
Reactor overpressure (1250 psig)	1	(2)	(2)	(2)	0
Hydrostatic test (1560 psig)	(2)	3	3	3	2
Rapid blowdown	1(3)	1	(2)	(2)	0
Loss of feedwater heater	(2)	10	(2)	(2)	1
Loss of alternating current power	(1)(2)	1	(2)	(2)	(1)
Loss of feedwater pumps	80	10	20	30	18
Turbine trip	(1)(2)	(2)	(2)	40	(1)
TOTAL (excludes startup/shutdown for MCF)	411	87	733	963	(4)

Notes:

(1) Not specified for MNGP.

(2) Not specified for this exemption analysis (fatigue exemption analyses do not include emergency and faulted events.

(3) Included with startup/shutdown.

(4) 80-year cycles used are as follows:

- Full pressure cycles : startup/shutdown (203) + 1250 psig tests (82) + 1560 psig tests (2) – 10 hydrotest cycles (except for MCF) = 287 cycles (MCF) or 277 cycles (others). The removal of 10 hydrotests is permitted in later Codes (NB-3226(e)).

- Significant pressure fluctuations include the same transients as in the original analyses except as noted below:

    - MCF: scram (165) + 1250 psig overpressure (0) + loss of FW pumps (18) = 183 cycles (1250 psig hydrotest excluded since it is included in full pressure cycles).

    - In-core detector assembly: Same as MCF (183) + loss of FW heater (1) = 184 cycles.

    - IRM/SRM dry tube: Same as in-core detector assembly (184) + additional pressure cycles for loss of FW pumps (18) = 202 cycles.

    - Power range detector assembly: Same as IRM/SRM dry tube (202) + additional pressure cycles for loss of FW pumps (18) = 220 cycles.

4.3.3 RPV Fatigue Analysis

TLAA Description

The RPV was originally designed for the initial 40-year license period in accordance with the ASME Code Section III, its interpretations, and applicable requirements, (including 1965 Summer Addenda) for Class 1 design requirements per USAR, Table 4.1-1. RPV fatigue analyses were performed for the following locations:

- recirculation outlet nozzle
- recirculation inlet nozzle
- steam outlet nozzle
- feedwater (FW) nozzle
- core spray nozzle
- core support structure
- bottom head and support skirt
- control rod drive penetrations
- vessel head bolts
- refueling bellows skirt

The RPV Class 1 fatigue analyses determined the effects of transient cyclic loadings resulting from changes in system temperature and pressure and for seismic loading cycles. The fatigue analyses evaluated explicit numbers and types of transients that were postulated for the 40-year operating period of the plant. These Class 1 fatigue analyses were required to demonstrate that the Cumulative Usage Factor (CUF) for each component will not exceed the design limit of 1.0 for all the postulated transients. The original, 40-year RPV fatigue analyses were evaluated for a 60-year operating period and for environmentally-assisted fatigue (EAF) as part of the MNGP initial LRA. The 60-year evaluations now serve as the CLB and have been identified as TLAAs for the SPEO.

TLAA Evaluation

The 80-year projected cycles (transients) used in the fatigue analyses are presented in Table 4.3.1-1. Other inputs used are identified for each analyzed location. The effects of EPU are included as required.

Recirculation Outlet Nozzle

The limiting location for fatigue is the safe end-to-pipe weld. This location has an analysis with bounding 60-year usage calculated as 0.0153.

The 80-year cycles for this location had events lumped as was done in the initial evaluation for 60 years. Lumping events into one group introduces a large amount of conservatism because the applied number of cycles for the most severe event increases by more than an order of magnitude. Since EPU, on the other hand, increases temperatures and pressures by a few percent, the existing analysis with lumping is bounding for EPU conditions.

Fatigue usage for 80 years is 0.0166 as presented in Table 4.3.3-1, is less than 1.0, and is therefore acceptable.

Recirculation Inlet Nozzle

This component has an analysis that includes the effects of EPU, with 60-year usage calculated as 0.1302 for the safe end and 0.1795 for the nozzle body. The 80-year cycles for the nozzle safe end and nozzle body had events lumped as was done in the 60-year analysis.

Fatigue usage for 80 years is 0.2154 for the safe end and 0.2030 for the nozzle body, as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Steam Outlet Nozzle

This component has an analysis with bounding 60-year usage calculated as 0.1918.

The 80-year cycles for the nozzle safe end and nozzle body had events lumped as was done in the initial evaluation for 60 years, except that transient “reduction to zero power” is excluded because it does not affect this location.

Lumping all events into one group introduces a large amount of conservatism because the applied number of cycles for the most severe event increases by more than an order of magnitude. Since EPU, on the other hand, increases temperatures and pressures by a few percent, the existing analysis with lumping is bounding for EPU conditions.

Fatigue usage for 80 years is 0.1872 as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Feedwater Nozzle

This component has analyses with bounding 60-year usage calculated as 0.840.

The 80-year cycles for this location had events lumped as was done in the previous analysis. Hot standby cycling (HSBC) cycles are determined as was done in the previous analysis:

- Startup/shutdown cycles are multiplied by 4 to yield HSBC cycles
- HSBC cycles after 1991 are also multiplied by 0.625 to reflect reduced severity

The previous fatigue usage calculation performed for EPU was used for the bounding location and adds 80-year usage. This bounding safe end location is near a rapid cycling location. Rapid cycling for this location is included.

For the nozzle body, the previous fatigue usage calculation was used as bounding, and adds 80-year usage using the cycles. The nozzle body location analyzed is between rapid cycling locations. To bound all nozzle body locations, the maximum rapid cycling is included as was done before for 60 years.

Fatigue usage for 80 years is 0.4490 for the safe end and 0.2615 for the nozzle body, as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Core Spray Nozzle

This component has an analysis with 60-year usage calculated as 0.1065 for the safe end and 0.0294 for the nozzle body. The 80-year cycles for this location had events lumped as was done in the initial evaluation for 60 years. The previous fatigue usage calculation performed for EPU was used and adds 80-year usage using the cycles from startups and shutdowns. The same process was done for the nozzle body.

Fatigue usage for 80 years is 0.1217 for the safe end and 0.0318 for the nozzle body, as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Core Support Structure

This location has an analysis with bounding 60-year usage calculated as 0.061.

The 80-year cycles for this location had events lumped as was done in the initial evaluation for 60 years except that the event, “reduction to zero power,” is excluded because it was not included for this location.

Rerate/EPU scaling was calculated for the load set pairs used in the analysis. These are based on warmup and hydrotest and warmup and improper start. EPU scaling factors were calculated based on original and rerate conditions, which bound EPU conditions. Since core flow is proportional to recirculation flow, and recirculation flow does not increase for rerate or EPU, no scaling is done for flow rate. The pressure scaling factor is bounding in both cases.

The fatigue usage was calculated using the values from the original analysis increased by the bounding EPU factor, 80-year cycles, and "N" interpolated from the applicable fatigue curve values from the ASME Code of Construction. The requirement to multiply alternating stress intensity by the ratio of the modulus of elasticity on the fatigue curve to that used in the analysis, which is applied for this location, was added in the Winter 1967 Addenda, setting a lower limit on the Code date.

Fatigue usage for 80 years is 0.0583 as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Bottom Head and Support Skirt

This location has an analysis with bounding 60-year usage calculated as 0.2832. Although the analysis with reduced conservatism is part of an EPU calculation package, the fatigue table was not adjusted for EPU. Subsequent fatigue updates used a fatigue table for the RPV shell at shroud support that is superseded.

The 80-year cycles for this location had events lumped as was done in the initial evaluation for 60 years. Lumping all events into one group introduces a large amount of conservatism because the applied number of cycles for the most severe event increases by more than an order of magnitude. Since EPU, on the other hand, increases temperatures and pressures by a few percent, the existing analysis with lumping is bounding for EPU conditions.

Fatigue usage for 80 years is 0.2868 as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Control Rod Drive Penetrations

This location has an analysis with bounding 60-year usage calculated as 0.2921. The 80-year cycles for this location had events lumped as was done in the initial evaluation for 60 years. Lumping all events into one group introduces a large amount of conservatism because the applied number of cycles for the most severe event increases by more than an order of magnitude. Since EPU, on the other hand, increases temperatures and pressures by a few percent, the existing analysis with lumping is bounding for EPU conditions.

Fatigue usage for 80 years is 0.3993 as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Vessel Head Bolts

This component has an analysis with bounding 60-year usage calculated as 0.5340. The 80-year cycles for this location had events lumped as was done in the initial evaluation for 60 years.

Fatigue usage for 80 years is 0.5206 as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

Refueling Bellows Skirt

This component has an analysis with bounding 60-year usage calculated as 0.8331. The 80-year cycles for this location had events lumped as was done in the initial evaluation for 60 years.

Fatigue usage for 80 years is 0.7674 as presented in Table 4.3.3-1, is less than 1.0 and is therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The fatigue analyses and corresponding CUF for all MNGP RPV locations will remain less than 1.0 during the SPEO.

The effects of fatigue on the intended functions of the RPV will be managed by the Fatigue Monitoring AMP (B.2.2.1) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.3.3-1 MNGP 80-year Fatigue Usage for RPV Locations

Location / Component	Projected U_{80}
Recirculation outlet nozzle	0.0166
Recirculation inlet nozzle, safe end	0.2154
Recirculation inlet nozzle, nozzle body	0.2030
Steam outlet nozzle	0.1872
Feedwater nozzle, safe end (Note 1)	0.4490
Feedwater nozzle, nozzle body (Note 1)	0.2615
Core spray nozzle, safe end	0.1217
Core spray nozzle, nozzle body	0.0318
Core support structure (Note 2)	0.0583
Bottom head and support skirt	0.2868
CRD penetrations	0.3993
Vessel head bolts (Note 3)	0.5206
Refueling bellows skirt (Note 3)	0.7674

Notes:

(1) Previous analysis for 60 years was a lumped usage factor. Calculation reduced by multiplying HSBC cycles after 1991 by 0.625 to reflect reduced severity.

(2) U_{60} recalculated based on Rerate/EPU scaling.

(3) Updated calculation for 80 years does not include the reduction to zero power transient because it does not affect this location.

4.3.4 Fatigue Analysis of RPV Internals

TLAA Description:

Fatigue analysis of the RPV internals (RVI) was performed for MNGP's initial LR using the ASME Boiler and Pressure Vessel Code, Section III, as a guide. The most significant fatigue loading occurs at the jet pump diffuser to baffle plate weld location; therefore, this location is bounding for all other fatigue affected components in the RVI. The original 40-year calculation showed a CUF of approximately 0.33. The resultant fatigue usage for 60 years was calculated to be approximately 0.5 in the MNGP LRA (USAR Appendix K).

The 60-year evaluation for this RVI location now serves as the bounding location for MNGP's CLB and has been identified as a TLAA for the RVI for the SPEO.

MNGP replaced its original steam dryer with a Westinghouse Nordic design steam dryer in 2011. Two analyses were performed on a new steam dryer to assess it for EPU operating conditions up to 2004 MWt. The conclusions of the analysis stated that the primary and secondary stress combinations determined by the analysis were below code allowables and that cyclic operation stresses were below those levels which require further low cycle fatigue analysis (USAR Section 12.2.2.17). Therefore, the steam dryer does not require evaluation.

TLAA Evaluation

This location has an analysis with bounding 60-year usage calculated as approximately 0.5.

In the initial analysis of this location, maximum strain occurred after a recirculation line break causing the RPV water level to drop, exposing the jet pump assembly to 540°F steam; the concurrent pressure drop results in LPCI injection at 120°F. Based on this description, this is the same event as the DBA used in the reanalysis. Given that a DBA is not expected to occur at all during the plant life, 1 cycle of DBA is still bounding for 80 years.

Fatigue usage was revised for a 60-year life by scaling up the number of cycles by 1.5, except for the DBA transient, resulting in a reported fatigue usage of approximately 0.5 even though the number of DBA cycles was still 1 and load set pairs without DBA contributed zero fatigue usage. Therefore, usage should not increase with increasing plant life unless DBA cycles increase.

Regarding EPU, given that pressure and temperature increase by 1 percent or less, the 50 percent increase in usage reported for 60 years, yielding approximately 0.5, is still bounding for 80 years with EPU.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The RVI component fatigue analysis for 60 years remains valid and is bounding for the SPEO in accordance with **10 CFR 54.21(c)(1)(i)**.

4.3.5 ASME Section III, Class 1

TLAA Description

MNGP piping systems were originally designed in accordance with ASA B31.1 and United States of America Standards (USAS) B31.1.0 which did not require that an explicit fatigue analysis be performed.

Reconciliation for the use of later editions of construction codes for modification to or replacement of piping and components had been performed in accordance with Section IWA-7210(c), Section XI of the ASME Code (Reference 4.7.22). The governing code for design, materials, fabrication and erection of piping, piping components, and pipe support modifications or replacements is ANSI B31.1, 1977 Edition including Addenda up to and including the Winter of 1978.

Portions of Class 1 systems such as the Reactor Recirculation, Core Spray and RHR inside drywell were required to be analyzed for fatigue in accordance with the ASME Code Section III for Nuclear Class 1 piping. The implementation of these requirements at MNGP were for the purpose of attaining a higher quality level and provide more detailed analysis to confirm protection of the RCS integrity.

The analyses for initial LR demonstrate that the 60 year CUF for the limiting components in all effected systems are below the ASME Code Section III allowable value of 1.0. Because these analyses are based on cycles postulated to occur in the current 60 year design life, they are TLAAs.

For the locations within the scope of this analysis, existing fatigue tables and 80-year cycle projections are used to calculate 80-year fatigue usage. If needed, fatigue tables are adjusted for rerate and/or EPU based on changes to temperature, pressure, and flow rate. The ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition with Addenda through Summer 1982 is used. (USAR Appendix K)

TLAA Evaluation

Recirculation System Lines Including RHR Shutdown Cooling Supply and Return Lines

The Recirculation and RHR piping systems were reanalyzed in 2005 through 2006. The Recirculation piping, including inlet nozzle safe ends and RHR supply and return lines to the containment penetrations, was replaced 1985. The bounding usage is 0.923 at an 18x4-in RHR supply branch within loop A small branch piping. This is at the connection to the RHR intertie line.

The bounding location was re-analyzed for 80-years with cycles adjusted to remove cycles from before piping replacement, modified to account for rerate/EPU and found to have an 80-year usage of 0.399. The usage is less than 1.0 and is therefore acceptable.

Core Spray Line

This carbon steel line has an analysis that does not include the effects of EPU, with usage calculated as 0.34 for the pipe at a pipe to valve weld. The location of interest is in the thermal zone with a maximum temperature of 350°F.

The 80-year cycles for this location were determined for the core spray piping. One thermal transient is defined, which varies depending on the piping section. The transient is a rapid thermal down ramp with flow which would be associated with a core spray injection. Operating basis earthquake (OBE) is combined with plant heatup and cooldown (with injection).

Rerate/EPU scaling is calculated for the load set pairs used in the analysis. These are based on a thermal transient and OBE. The thermal transient from 546°F to 80°F is the largest temperature delta evaluated and is used as the basis for EPU scaling. The calculation of EPU scaling factors is based on original and rerate conditions, which bound EPU conditions. The pressure scaling factor is bounding.

The bounding location was re-analyzed and found to have an 80-year usage of 0.436. Fatigue usage is less than 1.0 and is therefore acceptable.

RHR Intertie Line

An intertie line is provided at MNGP to connect the RHR suction line with the two RHR loop return lines. This four-inch line is equipped with isolation valves that are normally closed and receive a closure signal on a RHR Low Pressure Coolant Injection (LPCI) initiation signal. The purpose of this line is to reduce the potential for water hammer in the recirculation and RHR systems. The isolation valves are opened during a cooldown to establish recirculation flow through the RHR suction line and return lines, thereby ensuring a uniform cooldown of this piping. Flow is not permitted with the plant operating in Run Mode. The RHR loop return line isolation valves receive a closure signal on LPCI initiation.

The design transients for the RHR intertie line and associated 80-year projected cycles were determined. Three thermal transients are evaluated, and they are associated with flow in the intertie line during shutdown.

Rerate/EPU scaling is calculated for the load set pairs used in the analysis. The only evaluated thermal transient affected by EPU is the first thermal change during shutdown when flow is initiated in the RHR intertie line and temperature goes from 150°F to 546°F. The second temperature change, from 546°F to 375°F, is a slow ramp and is not used in the analysis. The last thermal transients represent a 375°F to 50°F step and a 50°F to 300°F step. The calculation of EPU scaling factors is based on original and rerate conditions, which bound EPU conditions. The pressure scaling factor is bounding.

The fatigue usage was calculated using the values from increasing by the bounding EPU factor as necessary, 80-year cycles, and “N” interpolated from the fatigue curve. The bounding location was re-analyzed and found to have an 80-year usage of 0.900. Fatigue usage is less than 1.0 and is therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The fatigue analyses and corresponding CUF for MNGP ASME Class 1 locations will remain less than 1.0 during the SPEO.

The effects of fatigue on the intended functions of components analyzed in accordance with ASME Section III, Class 1 requirements will be managed by the Fatigue Monitoring AMP (B.2.2.1) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

4.3.6 ASME Section III, Class 2 and 3 and ANSI B31.1

TLAA Description

A metal component may progressively degrade and lose its structural integrity when it is subjected to fluctuating loads, even at magnitudes less than the design static loads, due to metal fatigue. This mechanism of degradation can occur in flaw free components by developing cracks during service. Implicit fatigue-based maximum allowable stress calculations are performed for piping components designed to USAS / ANSI B31.1 requirements. ASME Section III Code Class 2 and 3 components are designed to requirements that are similar to the guidance in ANSI B31.1.

In addition, process piping that is subject to significant thermal expansion and contraction includes those that penetrate the drywell shell. Typically, these penetrations, which were designed to the ASME Code, Section III, Class B requirements, are a triple flued head design which has a guard pipe between the process piping and the penetration nozzle. The penetration assembly which provides the interface between the exterior of the process piping with the containment liner is typically known as a bellows. This permits the penetration to be vented to the drywell should a rupture of the hot line occur within the penetration. These containment penetration process bellows have been designed for a maximum of 7,000 operating cycles.

Although the code of construction for MNGP did not invoke fatigue analyses, a stress range reduction factor which is applied to the allowable stress range for expansion stresses (S_A) is required to account for cyclic thermal conditions. The allowable secondary stress range is 1.0 S_A for 7,000 equivalent full temperature thermal cycles or less and is incrementally reduced to 0.5 S_A for greater than 100,000 cycles.

TLAA Evaluation

As stated in MNGP USAR Supplement K, MNGP piping systems were originally designed in accordance with ASA B31.1, 1955 Edition and USAS B31.1.0, 1967 Edition which did not require that an explicit fatigue analysis be performed. Also, reconciliation for the use of later editions of construction codes for modifications to or replacement of piping and components has been performed in accordance with Section IWA- 7210(c), Section XI of the ASME Code. The governing code for design, materials, fabrication and erection of piping, piping components, and pipe support modifications or replacements is ANSI B31.1, 1977 Edition including Addenda up to and including the Winter of 1978.

Non-Class 1 components are excluded from the scope of this evaluation if they are in systems that may have normal/upset condition operating temperature that do not exceed 220°F. This is based on recommended values of 220°F for carbon steel or 270°F for austenitic stainless steel in the EPRI Fatigue Management Handbook (Reference 4.7.30).

Piping & instrument diagrams (P&IDs) were used to identify affected systems for this evaluation. In addition, specific station procedures were used to aid in this evaluation.

NUREG-2192, Table 2.1-6, provides examples of structures, components and commodity groups associated with non-Class 1 piping components. This includes component types such as piping, tubing, expansion joints, fittings, couplings, reducers, elbows, thermowells, flanges, fasteners, and welded attachments.

Section 4.3.2.1.1 of NUREG-2192 provides guidance for piping and components evaluated for fatigue parameters other than cumulative usage factor ($CUF_{en)}$ including fatigue-based maximum allowable stress calculations for components evaluated to B31.1 or ASME Code Class 2 and 3 requirements.

Table 4.3.6-1 provides a summary of the review performed to estimate 80 year cycles.

As described in the USAR supplement for initial license renewal, a conservative estimate of the number of thermal cycles experienced by the piping systems not analyzed to ASME Section III Class 1 requirements was approximated by using the maximum number of thermal cycles assumed in the reactor nozzle fatigue analyses. For MNGP the bounding number of cycles used for the qualification of a vessel nozzle is 1,500 for the feedwater nozzle. Table 4.3.6-1 was created to validate the approach used for initial license renewal.

Transient cycles on the bellows are composed of thermal cycles experienced by the associated system piping. The conservatively estimated cycles are provided in Table 4.3.6-1. Conservatively estimated cycles for the systems and penetration bellows not analyzed to Class 1 requirements show significant margin to the 7,000 cycle value used for these piping systems and containment process penetration bellows.

For MNGP the limiting system from a total cycle standpoint is feedwater, which has as its design basis 1,500 applied thermal cycles to the nozzles for a 40-year operating period. For the 80-year extended operating period, the number of cycles was estimated by multiplying the 40-year value times 2 which results in an estimated operating cycle expectation of 3,000 cycles. Since projected 80-year cycles (Table 4.3.1-1) are less that design cycles, this is a conservative estimate. This is less than half of the original requirement of 7,000 cycles.

Consequently, the current Class 2/3 piping and containment penetration bellows fatigue design criteria remain valid with significant margin for the 80 year SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

There are no in-scope systems that are projected to experience more than 3,000 full range temperature cycles for a period of 80 years based on plant operation to date. This provides significant margin to the 7,000 cycle value which would require further evaluation. Therefore, all of these systems at MNGP are suitable for extended operation without further evaluation and can be dispositioned in accordance with **10 CFR 54.21(c)(1)(i)**.

Table 4.3.6-1: Non-Class 1 Systems Evaluated

System	Process Penetration Bellows?	Notes
Feedwater	Yes	Includes both condensate and feedwater piping. Normal operating system, so conservatively estimate full range temperature cycles at 2 x 1500 design cycles for the feedwater nozzles (Total = 3000).
Nuclear Boiler Steam	Yes	Includes Main Steam from RPV to Main Turbine, Steam Line Drains, Extraction Steam, Supply to Steam Jet Air Ejectors, etc. Process penetration bellows included. Normal operating system, so conservatively estimate full range temperature cycles at 2 x 532 design cycles for the steam outlet nozzles (Total = 1064).
Reactor Pressure Relief	No	Cycles limited by number of pressure relief operations (could be multiple on certain scram events). Conservatively estimate full range temperature cycles at 5 x 270 design scram cycles (Total = 1350).
Vessel Instrumentation	No	Only instrumentation lines associated with RPV level inside containment sees higher temperatures. Normal operating system, so conservatively estimate full range temperature cycles at 3 x 289 design startup cycles (Total = 867).
Jet Pump Instrumentation	No	Only instrumentation lines inside containment sees higher temperatures. Normal operating system, so conservatively estimate full range temperature cycles at 3 x 289 design startup cycles (Total = 867).
Reactor Recirculation	No	Piping and instrumentation lines inside containment see higher temperatures. Normal operating system, so conservatively estimate full range temperature cycles at 2 x 205 design cycles for the recirculation inlet / outlet nozzles (Total = 410).
CRD Hydraulic	No	Higher temperature portion of the system includes scram discharge piping. Conservatively estimate full range temperature cycles at 2 x 270 design scram cycles (Total = 540).
RHR	Yes	System used for containment heat removal during HPCI and/or RCIC operation, but temperature exceeds screening temperature only during shutdown when RPV pressure is below system interlock pressure. Conservatively estimate full range temperature cycles at 3 x 289 design shutdown cycles (Total = 867).

Table 4.3.6-1: Non-Class 1 Systems Evaluated

System	Process Penetration Bellows?	Notes
Core Spray	Yes	Core Spray is a standby system only used for periodic surveillance testing at temperatures below the screening temperature. Therefore, the number of full range temperature cycles will be small (<100).
HPCI	Yes	HPCI is a standby system used for periodic surveillance testing (typically performed quarterly) as well as in response to certain scram events unless RCIC is used. Conservatively estimate 5 tests/year x 80 years of operation in addition to 2 x 270 design scram cycles (Total = 940).
RCIC	Yes	RCIC is a standby system used for periodic surveillance testing (typically performed quarterly) as well as in response to certain scram events unless HPCI is used. Conservatively estimate 5 tests/year x 80 years of operation in addition to 2 x 270 design scram cycles (Total = 940).
Reactor Water Cleanup	Yes	Normal operating system, so conservatively estimate full range temperature cycles at 3 x 289 design startup cycles (Total = 867).
Reactor Building Sample System	No	The station procedures associated with piping used for chemistry sampling indicate that sample lines are typically in service. Since this indicates they would only experience a full range temperature cycle once per operating cycle. Therefore, a conservative estimate is that the number of full range temperature cycles are likely not more than 2 x 80 years of operation (Total = 160).

4.3.7 Environmentally-Assisted Fatigue

TLAA Description

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on CUF_{en} must be examined for a set of sample critical components for the plant. These critical components should include those listed in NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components* (Reference 4.7.31), and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. Any additional limiting locations are identified through an EAF screening evaluation.

TLAA Evaluation

The environmental fatigue correction factor (F_{en}) is used to account for the effect of the reactor water environment. F_{en} methodology from NUREG/CR-6909 Revision 1 (Reference 4.7.32) is used. calculation of F_{en} varies in NUREG/CR-6909 between carbon steels, stainless steels, and Ni-Cr-Fe alloys. The EAF usage factor, U_{en}, is determined as Environmentally Assisted Fatigue Usage Factor (U_{en}) = (U) (F_{en}), where U is the fatigue usage.

Using bounding F_{en} values based on material type, maximum temperature, and dissolved oxygen, bounding U_{en} are estimated for all locations. Locations that have bounding U_{en} <1.0 are screened out. A location that is screened out must have an analysis with a similar or lower level of detail as the location that is potentially screening it out. Locations that were analyzed in NUREG/CR-6260 are included in Table 4.3.7-1.

The following locations correspond to locations analyzed in NUREG/CR-6260 for older vintage GE plants for EAF:

- shroud support (bounding for RPV shell and lower head)
- feedwater nozzle, safe end, and nozzle body
- recirculation inlet nozzle, safe end, and inlet nozzle body
- core spray nozzle, safe end, and nozzle body
- recirculation/ RHR piping, loop B point 251
- feedwater piping, points 54 and 15

The following RPV locations that were analyzed for fatigue usage do not need to be analyzed for EAF because they are not exposed to liquid reactor coolant during operation:

- steam outlet nozzle
- RPV shell and lower head (analyzed location is on the outside, and a shroud support location was chosen to bound inside locations)
- vessel head bolts
- refueling bellows skirt

Torus-attached penetrations for the HPCI turbine exhaust and RCIC turbine exhaust are attached to Class 2 piping and therefore do not need to be included in EAF screening. Additionally, the jet pump diffuser to baffle plate weld is neither pressure boundary nor core support, therefore this location does not need to be included in EAF screening. Therefore, among locations analyzed for fatigue but not EAF, the following additional locations need to be evaluated for EAF:

- recirculation outlet nozzle, node 1063, safe end-to-pipe weld
- control rod drive (CRD) penetrations, junction 5
- core spray piping, point 380
- RHR intertie (equalizer) line, node 01A

U_{en} was calculated for the six NUREG/CR-6260 locations and the four (4) additional locations that may be more limiting than these locations. Table 4.3.7-1 summarizes the results. U_{en} is less than 1.0 for all locations.

For initial screening, U_{en} was calculated using the bounding F_{en} for the applicable material and dissolved oxygen zone. Of the four additional locations above, the recirculation outlet nozzle screened out because its bounding U_{en} was less than 1.0. The three remaining locations screened in and were compared by thermal zone.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of environmentally-assisted fatigue on the intended functions of ASME Code, Section III and NUREG/CR-6260 component locations have been shown to be maintained with usage factors less than 1.0 through the SPEO.

The effects of EAF on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (B.2.2.1) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

Table 4.3.7-1: EAF Results

Component	Location	Material Type(2)	Projected Fatigue Usage (3)	F_{en}	Projected U_{en}
RPV Shell and Lower Head (1)	Shroud Support	CS/LAS	0.0583	8.408	0.490
Feedwater Nozzle (1)	Safe End	CS	0.2260	2.676	0.605
Feedwater Nozzle (1)	Nozzle Body	LAS	0.2038	2.257	0.460
Recirculation Nozzles (1)	Inlet Safe End	SS	0.2580	2.889	0.745
Recirculation Nozzles (1)	Inlet Nozzle Body	LAS	0.1916	3.598	0.689
CRD penetration	Junction 5, Location B	NBA	0.2021	2.748	0.555
Core Spray Nozzle and Piping (1)	Safe End	CS	0.0733	8.828	0.647
Core Spray Nozzle and Piping (1)	Nozzle Body	LAS	0.0318	8.828	0.280
Core Spray Nozzle and Piping	Point 380	CS	0.2169	3.214	0.697
Recirculation/RHR Piping	Loop B Point 251	CS	0.2031	3.429	0.697
RHR Intertie Line (1)	Node 01A	CS	0.2737	3.266	0.894
Feedwater Piping (1)	Point 54	CS	0.0238	12.425	0.296
Feedwater Piping (1)	Point 15	SS	0.0644	8.346	0.538

Notes:

(1) NUREG/CR-6260 location.

(2) Materials are carbon steel (CS), low-alloy steel (LAS), stainless steel (SS), and nickel-based alloy (NBA).

(3) Fatigue usage shown in this table is based on fatigue curves from NUREG/CR-6909, Revision 2.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

TLAA Description

Thermal, radiation, and cyclical aging analyses of electrical components developed to meet 10 CFR 50.49 requirements that specify a qualified life of 60 years are considered TLAAs for MNGP. 10 CFR 50.49, *Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants*, requires that an Environmental Qualification of Electric Equipment 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 DBA such as a loss-of-coolant accident (LOCA), high energy line break (HELB), or main steam line break (MSLB). 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

Aging evaluations for electrical components in the Environmental Qualification of Electric Equipment program that involve time-limited assumptions defined by the current operating term of 60 years have been identified as TLAAs for SLR because the criteria contained in 10 CFR 54.3 are met. Aging evaluations that qualify components for shorter periods, and that therefore require refurbishment, replacement, or extension of their qualified life, are not TLAAs.

TLAA Evaluation

The MNGP Environmental Qualification of Electric Equipment program (B.2.2.3) meets the requirements of 10 CFR 50.49 for the applicable components important to safety. Compliance with 10 CFR 50.49 provides reasonable assurance that the component can perform its intended functions during accident conditions after experiencing the effects of in- service aging. The MNGP Environmental Qualification of Electric Equipment program manages component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49 (f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

The Environmental Qualification of Electric Equipment program, which is an existing program that implements the requirements of 10 CFR 50.49, is viewed as an AMP for SLR under 10 CFR54.21(c)(1)(iii). Reanalysis of an aging evaluation to extend the qualifications of components is performed on a routine basis as part of the Environmental Qualification of Electric Equipment (B.2.2.3) AMP. The disposition of the TLAAs in accordance with 10 CFR 54.21(c)(1)(iii), which states that the effects of aging will be adequately managed for the SPEO, is chosen based on the fact the Environmental Qualification of Electric Equipment (B.2.2.3) Program will manage the aging effects of the electrical and instrumentation components associated with the EQ TLAAs.

NUREG-2192 states that the staff evaluated the Environmental Qualification of Electric Equipment program (10 CFR 50.49) and determined that it is an acceptable AMP to address environmental qualification according to 10 CFR 54.21(c)(1)(iii). The evaluation referred to in NUREG-2192 contains sections on “EQ Component Reanalysis Attributes, Evaluation, and Technical Basis” is the basis of the description provided below.

Component Reanalysis

Aging evaluations are normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation or by including new aging data. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, the majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters such as the assumed ambient temperature of the component, the activation energy, or in the application of a component (e.g., de-energized vs. energized). Important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met). These attributes are discussed in more detail below.

Analytical Methods

The MNGP Environmental Qualification of Electric Equipment program (B.2.2.3) generally uses the same analytical models in the reanalysis of an aging evaluation as those previously applied for the current evaluation. The Arrhenius methodology is an acceptable model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (i.e., normal radiation dose for the projected installed life plus applicable accident radiation dose). For SLR, acceptable methods for establishing the 80 year normal radiation dose includes multiplying the 60 year normal radiation dose by 1.33 (that is, 80 years/60 years) or using the actual calculated value for 80 years. The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods

Reducing excess conservatism in the component service conditions (e.g., temperature, radiation, cycles) used in the prior aging evaluation is the primary method used for a reanalysis per the Environmental Qualification of Electric Equipment program. Temperature data used in an aging evaluation should be conservative and based on plant design temperature or on actual plant temperature data. When used, plant temperature data can be obtained in several ways including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors. A representative number of temperature measurements are conservatively evaluated to establish the temperature used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as directly applying the plant temperature data in the evaluation or using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to the material activation energy values as part of a reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging. OE can also provide additional basis to justify changes in the qualification of the equipment.

Underlying Assumptions

EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. Plant modifications that have potential impact to the Environmental Qualification of Electric Equipment program are evaluated during the modification design process to determine the impact. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Action

The reanalysis of an aging evaluation could extend the qualified life of the component. If the qualification cannot be extended by reanalysis, the component is refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful.

Ongoing Qualification

Under the Environmental Qualification of Electric Equipment program (B.2.2.3), ongoing qualification techniques may be implemented when assessed margins, conservatisms, or assumptions do not support reanalysis of an EQ component of electric equipment important to safety. The requirements of 10 CFR 50.49 provide methods that are used to evaluate and maintain electric equipment qualification, including qualified life, for the SPEO.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

Based on a review of the MNGP Environmental Qualification of Electric Equipment program (B.2.2.3) and OE, the continued effective implementation of the program provides reasonable assurance that the aging effects will be managed and that EQ components will continue to perform their intended functions consistent with the CLB for the SPEO. Therefore, the MNGP Environmental Qualification of Electric Equipment program is an acceptable AMP for SLR under **10 CFR 54.21(c)(1)(iii)**.

4.5 CONTAINMENT LINER PLATE, METAL CONTAINMENTS AND PENETRATIONS FATIGUE

The MNGP primary containment was designed in accordance with the ASME Code, Section III, 1965 Edition with addenda up to and including Winter of 1965. Subsequently, during large scale testing for the Mark III containment system and the in-plant testing for Mark I primary containment systems, new suppression chamber hydrodynamic loads were identified. These loads are related to the loss-of-coolant-accident (LOCA) scenario and safety relief valve (SRV) operation. (References 4.7.22 and USAR Appendix K).

The following locations are analyzed.

- Vent System (Suppression Chamber, Vents, and Downcomers) and Torus Shell (Section 4.5.1)
- Safety Relief Valve (SRV) Discharge Piping Inside the Suppression Chamber (Section 4.5.2)
- External Piping and Penetrations (Section 4.5.3)
  - Torus Attached Piping
  - Torus Attached Piping Penetration
  - Ring Header
- Drywell-Suppression Chamber Vent Line Bellows (Section 4.5.4)
- Primary Containment Process Penetration Bellows (Section 4.5.5)

For these locations, existing fatigue tables and 80-year cycle projections were used to calculate 80-year fatigue usage. If needed, fatigue tables were adjusted for rerate and/or EPU based on changes to temperature, pressure, and flow rate. The ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition with Addenda through Summer 1982 was used.

4.5.1 <u>Fatigue Analysis of the Suppression Chamber, Vents, Downcomers, and Torus Shell</u>

TLAA Description

Hydrodynamic loads were updated subsequent to the original design for the containment suppression chamber vents and addressed in the MNGP LRA. These loads result from blowdown into the suppression chamber during a postulated LOCA and during SRV operation for plant transients. The results of analyses of these effects are presented in the MNGP USAR. Consequently, these analyses are TLAAs.

The limiting fatigue location for the suppression chamber, vents and downcomers is the vent header-downcomer intersection. The vent system fatigue for power rerate was determined to be 1.26 x 0.684 = 0.862. The calculation is based on a 26 percent increase in SRV cycles for power rerate and a current usage of 0.684. The current cumulative usage of 0.684 is the maximum value for a vent system component and occurs in the vent header at the downcomer-vent header intersection. The maximum cumulative usage for a vent system component weld is 0.390 in the SRV piping-vent line penetration.

The torus shell was evaluated for stress increases due to the installation of high capacity strainers in 1997, as well as the 26 percent increase in SRV cycles due to rerate conditions. The revised usage factor was 0.98.

TLAA Evaluation

The maximum usage value for 60-years was for a vent system component and occurred in the vent header at the downcomer-vent header intersection. This included 934 SRV discharges under a normal operating condition (NOC) and 50 SRV discharges under a small break accident (SBA).

Fatigue usage was recalculated for 80 years based on 699 projected SRV discharges under NOC and 74 SRV discharges under SBA, resulting in a maximum cumulative usage of 0.630.

Projected usage for the torus shell was recalculated using projected SRV cycles for NOC and increasing cycles for EPU for small break accident conditions by 47 percent from original design. Of the 699 projected SRV lifts, 506 were taken as single SRV lifts and 193 were taken as multiple SRV lifts. The ratio is consistent with the original design which had 676 single SRV lifts and 258 multiple SRV lifts.

Fatigue usage for the torus shell was 0.981 for 60 years. The largest impact on reducing this usage factor for 80 years of operation was using 699 projected SRV lifts, whereas the original evaluation assumed a total of 934 SRV lifts. The calculated cumulative usage factor for the torus shell for 80 years was 0.788.

Projected usage was calculated for 80-years including EPU and is presented in Table 4.5-1. Projected usage is below 1.0 and therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The fatigue analyses and corresponding CUF for MNGP Suppression Chamber, Vents, and Downcomers locations will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (B.2.2.1) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

4.5.2 Fatigue Analysis of the Safety Relief Valve (SRV) Discharge Piping Inside the Suppression Chamber

TLAA Description

The Reactor Pressure Relief System includes safety/relief valves (SRVs) located on the main steam lines within the drywell between the reactor vessel and the first isolation valve. The SRVs, which discharge to the suppression pool, provide two main protective functions:

- Overpressure relief - The valves open to limit the pressure rise in the reactor.
- Depressurization - The valves are opened to depressurize the reactor.

The Plant Unique Analysis Report (PUAR) describes the fatigue analysis of the SRV discharge lines (Reference 4.7.33). These analyses assume a limited number of SRV actuations throughout the life of MNGP and are therefore TLAAs.

The internal structures inside the suppression chamber include the catwalk and the monorail. These internal structures are designated as service level E components and as such, are not required to meet ASME Code acceptance limits.

TLAA Evaluation

The SRV piping fatigue usage value of 0.309 was increased by 26 percent to 0.389 for power rerate. Projected usage was calculated for normal operating condition (NOC) plus DBA and NOC plus small/intermediate break accident (SBA/IBA) with 50 SRV actuations postulated during accident (SBA/IBA) conditions and 934 SRV actuations postulated during normal operating conditions for a total of 984 postulated SRV actuations. Since projected SRV actuations during normal operation for 80-years are less than the 934 postulated, the usage of 0.309 is conservatively increased by 47 percent to account for EPU for 80-years. The conservatively calculated 80-year usage is therefore 0.309 x 1.47 = 0.454 and is presented in Table 4.5-1, which is less than 1.0 and therefore acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The fatigue analyses and corresponding CUF for MNGP SRV Discharge Piping Inside the Suppression Chamber will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (B.2.2.1) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

4.5.3 Fatigue Analysis of Suppression Chamber External Piping and Penetrations, Including Ring Header

TLAA Description

These analyses include the large and small bore torus attached piping, suppression chamber penetrations and the ECCS suction header. Fatigue analyses were completed that were based on cycles postulated to occur within the operating life of the plant. Therefore, these calculations are TLAAs.

TLAA Evaluation

The SRV discharge piping was identified as the most limiting of torus attached piping. The SRV piping therefore bounds all other torus attached piping and was evaluated in Section 4.5.2.

The torus attached piping penetration fatigue usage was evaluated for a postulated 26 percent increase in SRV cycles due to power rerate. This increased the previous usage from 0.859 to 0.985. That calculation was redone using projected SRV cycles during normal operation, conservatively retaining 1000 OBE cycles, and considering one postulated accident for 80 years. The usage for the postulated accident includes a 47 percent increase in cycles due to EPU.

Under normal operating conditions, 934 SRV actuations were assumed in the design basis and 258 of the 934 were multiple SRV actuations (SRV_m). At 80 years, 699 SRV actuations have been projected to occur. Of the 699 projected SRV lifts, 506 are taken as single SRV lifts and 193 are taken as multiple SRV lifts. The ratio is consistent with the original design that had 676 single SRV lifts and 258 multiple SRV lifts.

Projected usage was recalculated for 80 years based on the above as 0.8853 which is below 1.0 and therefore acceptable.

The ring header fatigue evaluation for power uprate documented the controlling component as the tee to penetration X-204C. The usage at the location was increased by 26 percent to account for an increase in SRV lifts due to power rerate. The EPU usage factor includes a 47 percent increase in cycles, resulting in an 80-year cumulative usage factor of 0.154. Projected usage is below 1.0 and therefore acceptable. The usage values associated with this TLAA are presented in Table 4.5-1.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The fatigue analyses and corresponding CUF for MNGP suppression chamber external piping and penetrations and ring header will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (B.2.2.1) through the SPEO in accordance with **10 CFR 54.21(c)(1)(iii)**.

4.5.4 <u>Drywell-to-Suppression Chamber Vent Line Bellows Fatigue Analysis</u>

TLAA Description

The drywell-to-suppression chamber vent line bellows are included in the Mark I Containment Long Term Program plant-unique analysis. A fatigue analysis of the vent line bellows demonstrates their adequacy to accommodate thermal and internal pressure load cycles for the life of the plant. As such this analysis is a TLAA.

TLAA Evaluation

The drywell to suppression chamber vent line bellows fatigue analysis conservatively considered 300 startup/shutdown cycles and 1 cycle due to postulated accident conditions with a resulting usage of 0.10. Since 203 startup/shutdown cycles are projected for 80-years of operation, the previous analysis is conservative, and the usage is acceptable for 80-years.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The drywell-to-suppression chamber vent line bellows fatigue analysis remain valid for the SPEO in accordance with **10 CFR 54.21(c)(1)(i)**.

4.5.5 Primary Containment Process Penetration Bellows Fatigue Analysis

TLAA Description

Containment pipe penetrations that are required to accommodate thermal movement have expansion bellows. The bellows are designed for a minimum number of operating cycles over the design life of the plant. Consequently, the primary containment process penetrations bellows cycle basis is a TLAA.

TLAA Evaluation

This evaluation was performed as part of the ASME Section III, Class 2 and 3 and ANSI B31.1 fatigue evaluation and is described in Section 4.3.6.

Consequently, the current piping and containment penetration bellows fatigue design criteria remain valid with margin for the 80-year extended operating period.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The containment penetration bellows fatigue design criteria remains valid for the SPEO in accordance with **10 CFR 54.21(c)(1)(i)**.

Table 4.5-1: Containment Fatigue Results

Location	U_{80}
Vent System Vent Header	0.630
Torus Shell	0.788
Ring Header	0.154
Torus Attached Piping including SRV Piping	0.454
Torus Attached Piping Penetration	0.885

4.6 OTHER PLANT-SPECIFIC TLAAS

4.6.1 Fatigue of Cranes

TLAA Description

Crane design considerations for nuclear plants in the 1960s were based on crane manufacturer's specifications for that period such as the Electric Overhead Traveling Cranes (EOCI) specification (Reference 4.7.34). This specification has since been superseded by the Crane Manufacturers Association of America (CMMA) specification (Reference 4.7.35). The MNGP Reactor and Turbine Building Cranes, manufactured prior to the issuance of CMAA-70 and ANSI B30.2, was designed to meet EOCI 61.

The primary difference between the EOCI and the CMMA specifications was for changes in the design of bridge girders. CMAA-70 allows the use of higher allowable stresses for the better grade of materials available today and also provides new design formulas. However, CMAA-70 did formally introduce the subject of structural fatigue, which ensured that the number of crane load cycles would prevent fatigue failure in its lifetime. A review of design specifications for cranes within the scope of SLR was performed to identify those cranes that were designed to or meet the intent of Crane Manufacturers Association of America (CMAA) Specification.

Generic Letter 81-07 raised an industry concern with regard to movement of heavy loads close to nuclear spent fuel, which required licensees of nuclear plants to comply with the requirements of NUREG-0612 (Reference 4.7.36). The NUREG presented an overall philosophy that provided a defense-in depth approach for controlling the handling of heavy loads. NUREG-0612 further required licensees to comply with the requirements of the current crane specification, CMAA-70. This required licensees to formally address the subject of metal fatigue for the cranes located in the vicinity of equipment important to safety.

The MNGP LRA evaluated the Reactor Building crane as a TLAA. A review of design specifications for the Turbine Building crane showed that it is designed to meet the intent of CMAA-70 and is therefore also included in this TLAA. 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, these analyses are considered TLAAs that must be re-evaluated for the SPEO.

TLAA Evaluation

Reactor Building Crane

The MNGP Reactor Building Crane System design conservatively considers that the following heavy load cycles will be required:

- 20 lifts per year of Reactor Building shield blocks and plugs,
- 2 lifts per year of the reactor vessel head,
- 2 lifts per year of the drywell vessel head,

- 2 lifts per year of the steam separator assembly and,
- 2 lifts per year of the steam dryer assembly.

In addition to these heavy load cycles, this SLR evaluation also considered the following cycles:

- 500 lifts as a conservative estimate for plant construction
- 4 lifts per year for miscellaneous activities
- 180 lifts for already completed ISFSI Casks (30 @ 6 lifts/cask)
- 4 lifts per year for planned ISFSI Casks (2022-2050, 6 lifts/cask)
- 120 lifts for Low Level Waste Cask Load (6 lifts/cask)

Without consideration for the fact that the modified Reactor Building Crane System was installed after several years of operation the total amount of heavy lifts during an 80 year life is 4,032 cycles. The Reactor Building Crane is conservatively designed to handle 70,000 heavy loads (Reference 4.7.22). However, the criteria of 20,000 heavy loads according to CMAA-70 Table 3.3.3.1.3-1 is used as a more conservative limit.

Listed in Table 4.6.1-1, the crane is expected to be subjected to less than 5,000 heavy lifts during the 80 year extended operating period, which is significantly less than the CMAA-70 limiting value of 20,000 cycles. Therefore, fatigue life is not significant for the operation of the Reactor Building Crane System and the current analysis remains valid for the SPEO.

Turbine Building Crane

The Turbine Building Crane is used to lift heavy loads like the generator rotors, high-pressure rotors and shells, and low-pressure rotors, hoods, and inner casings. A review of turbine heavy load liftings showed that there were 176 heavy lifts in MNGPs history. Using conservative assumptions, Table 4.6.1-2 shows that the crane is expected to be subjected to less than 3,000 heavy lifts during the 80 year SPEO, which is significantly less than the CMAA-70 limiting value of 20,000 cycles.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The MNGP crane load cycle limits have been projected through the SPEO in accordance with **10 CFR 54.21(c)(1)(i)**.

Table 4.6.1-1: MNGP Reactor Building Crane Load Cycles

Heavy Load Description	Frequency(1)	Years	Total number of lifts
Plant Construction Cycles (conservative assumption)	-	-	500
Reactor Building Shield Blocks and Plugs	20/year	80	1600
Reactor Vessel Head	2/year	80	160
Drywell Vessel Head	2/year	80	160
Steam Separator Assembly	2/year	80	160
Steam Dryer Assembly	2/year	80	160
Miscellaneous	4/year	80	320
Completed ISFSI Casks (2021): 30 @ 6 lifts/cask	-	-	180
Planned ISFSI Casks (2022-2029), 6 lifts/cask	4/year	8	192
Projected ISFSI Casks (2030-2050), 6 lifts/cask	4/year	20	480
Low Level Waste Cask Load: 6 lifts/cask	-	-	120
80-Year Total			**4032**

Note:

(1) Frequencies conservatively assumed an annual refueling outage.

Table 4.6.1-2: MNGP Turbine Building Crane Load Cycles

Heavy Load Description	Frequency(1)	Years	Total number of lifts
Plant Construction Cycles (conservative assumption)	-	-	500
Generator: 2 rotors	2/year	80	160
High-Pressure: 2 rotors, 2 shells	4/year	80	320
Low-Pressure: 2 rotors, 2 outer hoods, 2 inner casings	6/year	80	480
Miscellaneous	-	-	1000
80-Year Total			**2460**

Note:

(1) Frequencies conservatively assumed an annual refueling outage.

4.6.2 Fatigue Analyses of High-Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Turbine Exhaust Penetrations

TLAA Description

To evaluate the effects of testing the operability and performance of the turbine-pump units on a periodic basis MNGP conducted a detailed evaluation of the thermal cycles experienced during testing for initial LR. Since the number of cycles used in the evaluation is based on a 60-year plant life this is a TLAA.

TLAA Evaluation

HPCI Turbine Exhaust Penetration

The 40-year fatigue usage calculation of this location, which is also referred to as torus-attached penetration (TAP) X-221, resulted in a fatigue usage factor of 0.111. This is different from the value for the HPCI turbine exhaust penetration fatigue calculated in the MNGP LRA of 0.053 (Reference 4.7.22, Section 4.10). This difference is based on the method of evaluation.

The higher fatigue usage of 0.111 is conservatively multiplied by (80 years/40 years) to obtain a usage of 0.222 for 80 years of operation. Given this conservatism and the fact that, except for thermal and pressure cycles, none of the stresses increase due to EPU, 0.222 is bounding for 80 years with EPU.

RCIC Turbine Exhaust Penetration

The 40-year fatigue usage calculation of this location, which is also referred to as torus-attached penetration (TAP) X-212, resulted in a fatigue usage factor of 0.343. This is different from the value for the RCIC turbine exhaust penetration fatigue calculated in the MNGP LRA of 0.271 (Reference 4.7.22, Section 4.10). This difference is based on the method of evaluation.

For SLR, as with the HPCI turbine exhaust penetration, the total fatigue usage of 0.343 is conservatively multiplied by (80 years)/(40 years) to yield 0.686. Given this conservatism and the fact that, except for thermal and pressure cycles, none of the stresses increase due to EPU, 0.686 is bounding for 80 years with EPU.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The MNGP HPCI and RCIC turbine exhaust penetration fatigue analyses have been projected to the end of the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

4.6.3 Condensate Backwash Receiving Tank Fatigue Evaluation

TLAA Description

As part of the MNGP EPU program to increase maximum thermal power to 2,004 megawatts thermal (MWt), the application for which was submitted in 2008 (Reference 4.7.37), the largest impact of the Liquid Waste Management System would be the increase in liquid and wet solid waste resulting from more frequent backwashing of the condensate demineralizers. Backwashed sludge from the condensate demineralizers is collected in the Condensate Backwash Receiving Tank, where it is dewatered and packaged as solid waste for disposal off-site (USAR, Section 9.2.2.1).

Additionally, the internal pressure in the Condensate Backwash Receiving Tank was subsequently increased in support of the EPU. As a result of this pressure increase, a fatigue evaluation was performed to accommodate the increased backwash cycles performed at a greater airburst pressure. This fatigue evaluation projected a conservative value of 160 cycles (i.e., airbursts) per year, which extrapolates to 9,600 cycles over a 60 year operating period (40 years of operation plus 20 years of initial license renewal). Alternating stresses in the system were examined to determine an allowable number of cycles for the tank of 35,000 airbursts under normal and accident conditions. Applying this limit, the usage factor for 60 years of operation was found to be 0.28.

This fatigue evaluation of the Condensate Backwash Receiving Tank meets the six TLAA criteria, as defined by 10 CFR 54.3, and will require analysis as a new TLAA for the subsequent period of operation.

TLAA Evaluation

The original calculation assumed 160 cycles per year. Over 80 years of operation, the number of cycles estimated is 12,800. This is conservative as the increased pressure and number of backwash cycles was not implemented until EPU (2008). However, even with this conservatism, fatigue usage for this component is calculated to be 0.37, with significant margin to the limit of 35,000 cycles.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The fatigue parameter calculations are revised and shown to remain acceptable throughout the SPEO based on a revised projection of the cumulative number of each of the cyclic loadings to the end of the SPEO. The resulting fatigue parameter values are verified to remain less than 1.0 for the SPEO. The Condensate Backwash Receiving Tank fatigue evaluation has been projected to the end of the SPEO in accordance with **10 CFR 54.21(c)(1)(ii)**.

4.7 TLAA References

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APPENDIX A

UPDATED SAFETY ANALYSIS REPORT SUPPLEMENT

MONTICELLO NUCLEAR GENERATING PLANT

SUBSEQUENT LICENSE RENEWAL APPLICATION

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A. Aging Management Programs and Time-Limited Aging Analysis Activities

A.1 Introduction

The application for a renewed operating license for Unit 1 is required by 10 CFR 54.21(d) to include a USAR supplement. This chapter comprises the USAR supplement of the MNGP Subsequent License Renewal Application (SLRA) and includes the following sections:

Section A.1.1 contains a listing of the MNGP aging management programs (AMPs) for subsequent license renewal (SLR) in the order of NUREG-2191 programs, that is NUREG-2191 Chapter X and NUREG-2191 Chapter XI, including the status of the programs at the time the SLRA was submitted.

Section A.1.2 contains a listing of the time-limited aging analyses (TLAAs).

Section A.1.3 contains a discussion stating the relationship between the Northern States Power Company, a Minnesota corporation (NSPM) Quality Assurance (QA) Program at MNGP and the AMPs' corrective actions, confirmation process, and administrative controls elements.

Section A.1.4 contains a summary of the MNGP Operating Experience (OE) Program.

Section A.2 contains a summary of the MNGP programs used for managing the effects of aging. These AMPs are associated with either NUREG-2191 Chapter X or Chapter XI.

Section A.3 contains a summary of the TLAAs applicable to the subsequent period of extended operation (SPEO).

Section A.4 contains the MNGP SLR Commitment List and the AMPs' planned implementation schedule.

The integrated plant assessment for SLR identified new and existing AMPs necessary to provide reasonable assurance that systems, structures, and components (SSCs) within the scope of SLR will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the SPEO. The SPEO is defined as 20 years from the current renewed operating license expiration date.

A.1.1 Aging Management Programs

AMPs for MNGP SLR are listed in Table A-1 and described in Section A.2. The AMPs are listed chronologically as they appear in NUREG-2191, with the Chapter X AMPs first, followed by the Chapter XI AMPs. The MNGP AMPs are categorized as either existing AMPs or new AMPs for SLR. The existing MNGP AMPs are renamed and enhanced as necessary to more closely align with AMPs described in NUREG-2191.

Table A-1 reflects the status of the MNGP AMPs at the time of the SLRA submittal. Regulatory commitments, which include AMP enhancements and implementation schedules for MNGP AMPs are identified in the MNGP SLR Commitment List within Section A.4.

Table A-1
List of MNGP Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
X.M1	Fatigue Monitoring (Section A.2.1.1)	Existing
X.M2	Neutron Fluence Monitoring (Section A.2.1.2)	Existing
X.E1	Environmental Qualification of Electric Equipment (Section A.2.1.3)	Existing
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section A.2.2.1)	Existing
XI.M2	Water Chemistry (Section A.2.2.2)	Existing
XI.M3	Reactor Head Closure Stud Bolting (Section A.2.2.3)	Existing
XI.M4	BWR Vessel ID Attachment Welds (Section A.2.2.4)	Existing
XI.M7	BWR Stress Corrosion Cracking (Section A.2.2.5)	Existing
XI.M8	BWR Penetrations (Section A.2.2.6)	Existing
XI.M9	BWR Vessel Internals (Section A.2.2.7)	Existing
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section A.2.2.8)	New
XI.M17	Flow-Accelerated Corrosion (Section A.2.2.9)	Existing
XI.M18	Bolting Integrity (Section A.2.2.10)	Existing
XI.M20	Open-Cycle Cooling Water System (Section A.2.2.11)	Existing
XI.M21A	Closed Treated Water Systems (Section A.2.2.12)	Existing
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section A.2.2.13)	Existing
XI.M24	Compressed Air Monitoring (Section A.2.2.14)	Existing
XI.M26	Fire Protection (Section A.2.2.15)	Existing
XI.M27	Fire Water System (Section A.2.2.16)	Existing
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks (Section A.2.2.17)	New
XI.M30	Fuel Oil Chemistry (Section A.2.2.18)	Existing
XI.M31	Reactor Vessel Material Surveillance (Section A.2.2.19)	Existing
XI.M32	One-Time Inspection (Section A.2.2.20)	New
XI.M33	Selective Leaching (Section A.2.2.21)	Existing

Table A-1
List of MNGP Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.M35	ASME Code Class 1 Small-Bore Piping (Section A.2.2.22)	New
XI.M36	External Surfaces Monitoring of Mechanical Components (Section A.2.2.23)	Existing
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section A.2.2.24)	New
XI.M39	Lubricating Oil Analysis (Section A.2.2.25)	Existing
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section A.2.2.26)	Existing
XI.M41	Buried and Underground Piping and Tanks (Section A.2.2.27)	Existing
XI.M42	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section A.2.2.28)	New
XI.S1	ASME Section XI, Subsection IWE (Section A.2.2.29)	Existing
XI.S3	ASME Section XI, Subsection IWF (Section A.2.2.30)	Existing
XI.S4	10 CFR Part 50, Appendix J (Section A.2.2.31)	Existing
XI.S5	Masonry Walls (Section A.2.2.32)	Existing
XI.S6	Structures Monitoring (Section A.2.2.33)	Existing
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section A.2.2.34)	Existing
XI.S8	Protective Coating Monitoring and Maintenance (Section A.2.2.35)	Existing
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.2.36)	Existing
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits (Section A.2.2.37)	Existing
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.2.38)	Existing

Table A-1
List of MNGP Aging Management Programs

NUREG-2191 Section	Aging Management Program	Existing AMP or New AMP
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.2.39)	New
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.2.40)	New
XI.E4	Metal-Enclosed Bus (Section A.2.2.41)	Existing
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.2.42)	Existing

A.1.2 Time-Limiting Aging Analyses

The TLAA summaries applicable to MNGP during the SPEO are identified in Table A-2 and described in the sections subordinate to Section A.3:

Table A-2
List of Time-Limited Aging Analyses

Category (Section)	Time-Limited Aging Analyses Name	Section
Reactor Vessel Neutron Embrittlement (A.3.2)	Neutron Fluence Projections	A.3.2.1
	RPV Materials Upper-Shelf Energy	A.3.2.2
	Adjusted Reference Temperature for RPV Materials Due to Neutron Embrittlement	A.3.2.3
	RPV Thermal Limit Analysis: Operating P-T limits	A.3.2.4
	RPV Circumferential Weld Examination Relief	A.3.2.5
	RPV Axial Weld Failure Probability	A.3.2.6
	Reflood Thermal Shock Analysis of the RPV	A.3.2.7
	Reflood Thermal Shock Analysis of the RPV Core Shroud	A.3.2.8
	Loss of Preload for Core Plate Rim Holddown Bolts	A.3.2.9
	Susceptibility to IASCC	A.3.2.10
Metal Fatigue (A.3.3)	80-Year Transient Cycle Projections	A.3.3.1
	ASME Section III, Class 1 Fatigue Waivers	A.3.3.2
	RPV Fatigue Analysis	A.3.3.3
	Fatigue Analysis of RPV Internals	A.3.3.4
	ASME Section III, Class 1	A.3.3.5

Table A-2
List of Time-Limited Aging Analyses

Category (Section)	Time-Limited Aging Analyses Name	Section
	ASME Section III, Class 2 and 3 and ANSI B31.1	A.3.3.6
	Environmentally-Assisted Fatigue	A.3.3.7
Environmental Qualification of Electric Equipment (A.3.4)	Environmental Qualification of Electrical Equipment	A.3.4
Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses (A.3.5)	Fatigue Analysis of the Suppression Chamber, Vents, and Downcomers	A.3.5.1
	Fatigue Analysis of the Safety Relief Valve (SRV) Discharge Piping Inside the Suppression Chamber and Internal Structures	A.3.5.2
	Fatigue Analysis of Suppression Chamber External Piping and Penetrations	A.3.5.3
	Drywell-to-Suppression Chamber Vent Line Bellows Fatigue Analysis	A.3.5.4
	Primary Containment Process Penetration Bellows Fatigue Analysis	A.3.5.5
Other Plant-Specific TLAAs (A.3.6)	Fatigue of Cranes	A.3.6.1
	Fatigue Analyses of High-Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Turbine Exhaust Penetrations	A.3.6.2
	Condensate Backwash Receiving Tank Fatigue Analysis	A.3.6.3

A.1.3 Quality Assurance Program and Administrative Controls

The MNGP QA Program for MNGP implements the requirements of 10 CFR Part 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 NSPM QA Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the SR and NSR SSCs and commodity groups that are included within the scope of the AMPs. Generically, the three elements are applicable as follows.

The corrective action, confirmation process, and administrative controls of the NSPM QA Program are applicable to all AMPs and activities during the SPEO. The NSPM QA Program procedures, review and approval processes, and administrative controls are implemented, as described in the NSPM Topical QA Report, in accordance with the requirements of 10 CFR Part 50, Appendix B. The NSPM QA Program applies to all SCs that have aging effects managed by a MNGP AMP. Corrective actions and administrative (document) control for both SR and NSR SCs are accomplished in accordance with the established MNGP corrective action program (CAP) and document control program and are applicable to all AMPs and associated activities during the SPEO. The confirmation process is part of the CAP and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspections required by the confirmation process are documented in accordance with the CAP.

A.1.4 Operating Experience Program

The MNGP OE Program captures the OE from plant-specific and industry sources and is systematically reviewed on an ongoing basis in accordance with the NSPM QA Program. This OE program also meets the provisions of NUREG-0737, *Clarification of TMI Action Plan Requirements*, Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff."

The MNGP OE Program interfaces with and relies on active participation in the Institute of Nuclear Power Operations (INPO) OE program, as endorsed by the U.S. Nuclear Regulatory Commission (NRC). In accordance with these programs, all incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development associated with Electric Power Research Institute (EPRI), Nuclear Energy Institute (NEI), or any other industry initiatives are also reviewed. Items so identified are further evaluated, and the AMPs are either enhanced, or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed. Training on age-related degradation and aging management is provided to those personnel responsible for implementing the AMPs and to those who may screen, assign, evaluate, or otherwise process plant-specific and industry OE. Plant-specific OE associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the MNGP OE Program.

A.2 Aging Management Programs

A.2.1 NUREG-2191 Chapter X Aging Management Programs

This section provides USAR summaries of the NUREG 2191 Chapter X AMPs associated with TLAAs.

A.2.1.1 Fatigue Monitoring

The MNGP Fatigue Monitoring AMP is an existing preventive program that manages fatigue damage of the reactor pressure vessel components, reactor coolant pressure boundary (RCPB) piping components, and other components. This AMP provides an acceptable basis for managing fatigue of components that are subject to fatigue or other types of cyclical loading TLAAs (Section A.3.3) to provide reasonable assurance that they remain valid in accordance with 10 CFR 54.21 (c)(1)(iii). The program monitors and tracks the number of occurrences of design basis transients assessed in the applicable fatigue or cyclical loading analyses, including those in applicable American Society of Mechanical Engineers (ASME) Section III, Class 1 cumulative usage factor (CUF) analyses, fatigue waivers, environmental-assisted fatigue analyses (CUF_{en} analyses), and maximum allowable stress range reduction/expansion stress analyses for ANSI B31.1 components. No cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses that are based on cycle-based loading assumptions have been dispositioned in accordance with

10 CFR 54.21(c)(1)(iii), therefore this program does not apply to flaw growth, flaw tolerance, or fracture mechanics analyses.

This AMP manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the applicable structures and components (SCs) through performance of activities that monitor one or more relevant analysis parameters, such as CUF values, CUF_{en} values, and design transient cycle limit values. The AMP also utilizes applicable acceptance criteria (limits) to verify the continued acceptability of existing analyses through transient cycle counting and the calculation (CA), 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. The MNGP Water Chemistry AMP (Section A.2.2.2) monitors environmental and chemistry parameters for calculating environmental fatigue multipliers (F_{en} values).

When a program acceptance criterion is exceeded the condition is entered into the CAP 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.

A.2.1.2 Neutron Fluence Monitoring

The Neutron Fluence Monitoring AMP 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 assessments 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 extended beltline region and RVI components subject to a reactor coolant and neutron flux environment.

The program verifies the continued acceptability of existing analyses through neutron fluence monitoring, assess susceptibility of RVI components to neutron irradiation-related damage, and determines and monitors the extent of the RPV beltline region. Thus, the program ensures the analyses involving neutron fluence inputs continue to meet the appropriate limits defined in the 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 determining RPV neutron fluence for the beltline region are consistent with U.S. NRC Regulatory Guide (RG) 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*. The methods and assumptions used for the 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/cm^2 (E >1 MeV) at 72 Effective Full Power Years (EFPY). The methods for projecting reactor vessel internal component fast neutron fluence values are not governed by regulatory guidance or requirements.

The neutron fluence 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 and P-T 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 reflood thermal shock analysis of the RPV, reflood thermal shock analysis of the RPV core shroud, RPV thermal limit analysis (operating P-T limits), RPV circumferential weld examination relief, RPV axial weld failure probability, and aging effect assessments for BWR reactor internals that are induced by neutron irradiation exposure mechanisms.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H, requirements, and through implementation of the Reactor Vessel Material Surveillance program, provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

A.2.1.3 Environmental Qualification of Electric Equipment

The Environmental Qualification of Electrical Components AMP implements the EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an Environmental Qualification of Electric Equipment program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform their safety function in those harsh environments after the effects of in-service aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ.

As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished, replaced, or has its qualification extended prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for EQ equipment that specify a qualification of at least 60 years are TLAAs for SLR (Section A.3.4).

Equipment covered by this AMP has been evaluated to determine if the existing EQ aging analyses can be projected to the end of the SPEO by reanalysis. When analysis cannot justify a qualified life in excess of the SLR period, then the component parts are replaced, refurbished, or requalified prior to exceeding the qualified life as required by 10 CFR 50.49. Aging evaluations for EQ equipment that specify a qualification of at least 60 years are TLAAs for SLR. The MNGP Environmental Qualification of Electrical Equipment AMP is implemented in accordance with 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii).

A.2.2 NUREG-2191 Chapter XI Aging Management Programs

This section provides USAR summaries of the NUREG-2191 Chapter XI AMPs credited for managing the effects of aging.

A.2.2.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP is an existing AMP that is part of the MNGP ASME Section XI Inservice Inspection program and is also supplemented by implementing the guidelines of the BWRVIP program documents. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP provides for condition monitoring of ASME Code Class 1, 2, and 3 pressure retaining components and their integral attachments.

The MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP manages the aging effects of loss of material, cracking, and reduction in fracture toughness. The MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP consists of periodic volumetric, surface, and/or visual examination of ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, signs of degradation, and corrective actions. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC in accordance with 10 CFR 50.55a prior to implementation during the SPEO.

All examinations and inspections preformed in accordance with the program plan are documented by records and reports, which are submitted to the NRC as required by IWA-6000.

A.2.2.2 Water Chemistry

The MNGP Water Chemistry AMP, previously known as the Plant Chemistry Program, is an existing AMP that mitigates the aging effects of loss of material due to corrosion, cracking due to stress corrosion cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to treated water.

The MNGP Water Chemistry AMP controls treated water for impurities (e.g., chloride and sulfate) that accelerate corrosion. The MNGP Water Chemistry AMP relies on monitoring and control of water chemistry to keep peak levels of various contaminants below system-specific limits based on the industry guidelines contained in the BWRVIP-190 (EPRI-3002002623).

The MNGP Water Chemistry AMP is augmented by various AMPs, notably, the MNGP One-Time Inspection AMP (Section A.2.2.20), to verify the AMP effectiveness in managing corrosion-susceptible components (i.e., components located in areas exposed to low or stagnant flow).

A.2.2.3 Reactor Head Closure Stud Bolting

The MNGP Reactor Head Closure Studs Bolting AMP is an existing AMP that is part of the MNGP ASME Section XI Inservice Inspection program (Section A.2.2.1). The Reactor Head Closure Stud Bolting AMP will use the edition and addenda of

ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Replacement reactor head studs available for use at MNGP include preventive measures described in RG 1.65, *Material and Inspection for Reactor Vessel Closure Studs*.

This AMP provides for condition monitoring of the reactor head closure stud bolting and manages the aging effects of cracking due to SCC or intergranular stress corrosion cracking (IGSCC) and loss of material due to wear or corrosion for reactor head closure stud bolting. This is accomplished through effective monitoring techniques, acceptance criteria, corrective actions, and administrative controls.

This AMP includes procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi, as well as requirements to preclude the use of sulfide-containing lubricant.

A.2.2.4 <u>BWR Vessel ID Attachment Welds</u>

The MNGP BWR Vessel ID Attachment Welds AMP is part of the MNGP ASME Section XI Inservice Inspection Program (Section A.2.2.1). The BWR Vessel ID Attachment Welds AMP is in accordance with approved relief request under the BWRVIP Administrative Manual and provides for condition monitoring of the BWR Vessel ID Attachment Welds.

The BWR water chemistry is controlled per the EPRI guidelines of BWRVIP-190 Revision 1 (TR-3002002623), Volume 1: *BWR Water Chemistry Guidelines – Mandatory, Needed, and Good Practice Guidance*.

AMP activities incorporate the inspection and evaluation guidelines of BWRVIP-48-A, *Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines*. Crack growth evaluations follow the guidance of BWRVIP-14-A, BWRVIP-59-A, or BWRVIP-60-A, as appropriate.

The AMP is updated periodically as required by 10 CFR 50.55a and the BWRVIP.

A.2.2.5 <u>BWR Stress Corrosion Cracking</u>

The program manages cracking due to IGSCC for all BWR piping and piping welds made of austenitic stainless steel and nickel alloy that are 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93°C (200°F) during power operation, regardless of code classification.

The BWR water chemistry is controlled per the EPRI guidelines of BWRVIP-190 Revision 1 (TR-3002002623), Volume 1: *BWR Water Chemistry Guidelines – Mandatory, Needed, and Good Practice Guidance*.

The program performs volumetric examinations to detect and manage IGSCC in accordance with NRC GL 88-01. The alternate inspection schedule in BWRVIP-75-A is not used. This program relies on the staff-approved positions that are described in NUREG-0313, Revision 2, and GL 88-01 and its Supplement 1 regarding selection of IGSCC-resistant materials, solution heat treatment and stress improvement processes, water chemistry, weld overlay reinforcement, partial replacement, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements. All welds are classified as IGSCC Category A in accordance with NUREG-0313 and are incorporated into the Risk-Informed Inservice Inspection program in accordance with staff-approved EPRI Topical Report TR-112657, Revision B-A and Code Case N-716, subject to approval of ASME Code relief requests prior to or during the SPEO.

The AMP is updated periodically as required by 10 CFR 50.55a and the BWRVIP.

A.2.2.6 BWR Penetrations

The MNGP BWR Penetrations AMP is an existing program that is part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (Section A.2.2.1). The BWR Penetrations AMP is in accordance with the approved ASME Section XI Edition/Addenda and provides for condition monitoring of the BWR penetrations.

The BWR water chemistry is controlled per the EPRI guidelines of BWRVIP-190 Revision 1 (TR-3002002623), Volume 1: *BWR Water Chemistry Guidelines – Mandatory, Needed, and Good Practice Guidance*.

AMP activities incorporate the inspection and evaluation guidelines of BWRVIP-49-A, *BWR Vessel and Internals Project, Instrument Penetration Inspection and Flaw Evaluation Guidelines for Instrument Penetrations*, BWRVIP-47-A, *BWR Lower Plenum Inspection and Flaw Evaluation Guidelines*, and BWRVIP-27-A, *BWR Vessel and Internals Project, BWR Standby Liquid Control System/Core Plate Delta-P Inspection and Flaw Evaluation Guidelines for the Standby Liquid Control System*. Crack growth evaluations follow the guidance of BWRVIP-14-A, BWRVIP-59-A, or BWRVIP-60-A, as appropriate.

The AMP is updated periodically as required by 10 CFR 50.55a and the BWRVIP.

A.2.2.7 BWR Vessel Internals

The MNGP BWR Vessel Internals program is an existing program that includes inspections and flaw evaluations in conformance with the guidelines of applicable staff-approved BWRVIP documents and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel.

The BWR water chemistry is controlled per the EPRI guidelines of BWRVIP-190 Revision 1 (TR-3002002623), Volume 1: *BWR Water Chemistry Guidelines – Mandatory, Needed, and Good Practice Guidance*.

The program manages the effects of cracking due to SCC, IGSCC, or IASCC, cracking due to cyclic loading (including flow-induced vibration), loss of material due to wear, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation.

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable staff-approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB 2500-1. The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking of the components. This program also manages loss of preload for jet pump assembly holddown beam bolts by performing visual inspections or stress analyses for adequate structural integrity.

This program performs evaluations to determine whether supplemental inspections in addition to the existing BWRVIP examination guidelines are necessary to adequately manage loss of fracture toughness due to thermal or neutron embrittlement and cracking due to IASCC for the SPEO. If the evaluations determine that supplemental inspections are necessary for certain components based on neutron fluence, cracking susceptibility and fracture toughness, the program conducts the supplemental inspections for adequate aging management.

The AMP is updated periodically as required by 10 CFR 50.55a and the BWRVIP.

A.2.2.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP is a new condition monitoring program that will provide assurance that RCPB CASS components (i.e., pump casings) with the potential for significant thermal aging embrittlement meet their intended functions. The 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. The MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (Section A.2.2.1) is augmented by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program which will monitor the aging effect of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250°C (482°F). MNGP does not have any Class 1 piping or fittings fabricated from CASS. The Class 1 reactor recirculation pump casings and covers are fabricated from CASS.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, and percent ferrite. Components with the potential for significant thermal aging embrittlement will be managed through qualified visual inspections, such as enhanced visual examination or qualified ultrasonic testing (UT) methodology.

Inspections are not required for components for which thermal aging embrittlement is not significant. In addition, screening for ASME Code Class 1 CASS valve bodies for significance of thermal aging embrittlement is not required, because the existing ASME Section XI inspection requirements are adequate for managing the aging effects of Class 1 valve bodies. Reactor vessel internal components fabricated from CASS are not within the scope of this AMP and are managed by the BWR Vessel Internals (Section A.2.2.7) AMP.

A.2.2.9 Flow-Accelerated Corrosion

The MNGP Flow-Accelerated Corrosion (FAC) AMP is an existing AMP that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. This AMP is based on industry guidelines (Nuclear Safety Analysis Center document, (NSAC) 202L R4) and industry OE.

A predictive analytical software EPRI computer 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. Additionally, the software tool, FAC Manager™, with the erosion module, is used to evaluate components for both FAC and erosion. The software QA classification for CHECWORKS™ and FAC Manager™ are Classification Level 2, which is important to compliance with regulatory requirements/commitments, required by nuclear laws or regulations, or whose failure to operate as expected may have an indirect effect on nuclear plant safety, in accordance with the Software QA Program.

The AMP includes (a) identifying all FAC susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analyses of FAC models and, with consideration of OE, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

The MNGP FAC AMP also manages wall thinning caused by erosion mechanisms in limited situations where periodic monitoring is used in lieu of eliminating the cause, typically due to a design or operational condition. These limited situations are based on plant-specific OE and will be monitored similar to other FAC locations that are not modeled.

A.2.2.10 Bolting Integrity

The MNGP Bolting Integrity AMP manages the aging affects associated with closure bolting for pressure-retaining components in the scope of license renewal. Preventive measures to preclude or minimize loss of preload and cracking include material selection, thread lubricant control, assembly and torque requirements, and repair and replacement requirements. These activities rely on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339 and EPRI NP-5769, with the exceptions noted in NUREG-1339 for SR bolting. The program also relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI Report 1015336 and EPRI Report 1015337.

This AMP includes periodic visual inspection of closure bolting for indications of cracking, loss of preload, and loss of material (due to general, pitting, and crevice corrosion, MIC, and wear) as evidenced by leakage. Alternative means of inspection or testing are used for closure bolting in submerged locations or in piping systems containing air or gas for which leakage is difficult to detect.

The MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (Section A.2.2.1) includes inspections of SR closure bolting and supplements this Bolting Integrity AMP. Aging effects associated with closure bolting for heating, ventilation, and air conditioning systems are managed by the MNGP External Surfaces Monitoring of Mechanical Components AMP (Section A.2.2.23).

A.2.2.11 Open-Cycle Cooling Water System

The MNGP Open-Cycle Cooling Water System AMP is an existing AMP that manages aging effects caused by exposure of internal surfaces of piping, piping components, strainer elements, valves bodies, orifices, pump casings (ESW, hoses (carbon steel and stainless steel), and heat exchanger components to an environment of raw, untreated (e.g., service) water. This AMP 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 specific heat exchangers, (c) routine inspection and maintenance so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of SR SSCs serviced by the raw water systems. Inspection methods primarily include visual inspection and eddy current testing (ECT), but also include ultrasonic testing (UT) and radiography testing (RT) as needed. The MNGP Open-Cycle Cooling Water System AMP complies with the MNGP response to NRC GL 89-13. Resultant commitments made to comply with GL 89-13 have been incorporated into plant procedures and programs. This AMP also includes enhancements to the guidance in NRC GL 89-13 that address OE such that aging effects are adequately managed.

A.2.2.12 Closed Treated Water Systems

The MNGP Closed Treated Water System AMP, previously known as the Closed-Cycle Cooling Water AMP, is an existing AMP and is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. This AMP manages aging effects in Closed-Cycle Cooling Water Systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink. This AMP consists of: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion and microbiological activity are minimized; (b) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation.

The MNGP Closed Treated Water Systems AMP utilizes EPRI Closed Cooling Water Chemistry Guideline per NUREG-2191, XI.M21A as modified by SLR-ISG-2021-02-MECHANICAL, Updated Aging Management Criteria for Mechanical Portions of SLR Guidance.

A.2.2.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, which is implemented through plant procedures and preventive maintenance, manages loss of material of structural components for heavy load and fuel handling components within the scope of license renewal. The program includes periodic visual to detect loss of material due to corrosion, wear, cracking, and indications of loss of preload for load handling bridges, structural members, structural components, and bolted connections. Functional tests are also performed to assure their integrity. This program relies on the guidance in NUREG-0612 and ASME B30.2.

A.2.2.14 Compressed Air Monitoring

The MNGP Compressed Air Monitoring AMP is an existing program that inspects, monitors, and tests the Instrument and Service Air System to provide reasonable assurance that the system will perform their intended function. The MNGP Compressed Air Monitoring AMP manages the aging effect of loss of material due to corrosion in Compressed Air System piping and piping components located downstream of system air dryers, as well as piping and piping components exposed to an internal gas environment.

The MNGP Compressed Air Monitoring AMP includes monitoring of water (moisture), and other contaminants as a preventive measure to keep compressed air quality within specified limits.

The MNGP Compressed Air Monitoring AMP incorporates the guidance from the most current ANSI/ISA standards, and will incorporate the guidance from ASME OM 2012, Division 2, Part 28, and EPRI TR-108147 for testing and monitoring of air quality and moisture.

Opportunistic visual inspections of components for indications of loss of material due to corrosion will be performed. Additionally, inspection and test results are trended to provide for the timely detection of aging effects prior to loss of intended function.

A.2.2.15 Fire Protection

The MNGP Fire Protection Program is an existing condition and performance program that includes a fire barrier visual inspection program, Cable Spreading Room halon fire suppression system visual inspections, and functional testing. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barriers (e.g., walls, ceilings, and floors), fireproofing materials, fire damper assemblies, and periodic visual inspection and functional tests of associated fire rated doors to ensure that their functionality is maintained.

A.2.2.16 Fire Water System

The MNGP Fire Water System AMP is an existing AMP. This AMP manages aging effects associated with water-based thinning, cracking, and flow blockage due to fouling by performing periodic visual inspections, tests, and flushes in accordance with the 2011 Edition of NFPA 25.

Testing or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, is performed in accordance with NFPA 25. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (1) normally dry but periodically subjected to flow and (2) cannot be drained or allow water to collect are subjected to augmented testing beyond that specified in NFPA 25, including: (a) periodic system full flow tests at the design pressure and flow rate or internal visual inspections and (b) piping volumetric wall-thickness examinations. Preventive actions (i.e., periodic flushes and biocide utilization) as well as periodic maintenance, testing, and inspection activities of the water-based fire protection systems are implemented to provide reasonable assurance that the fire water systems are capable of performing their intended functions. Inspections and testing are performed in accordance with guidance of applicable NFPA codes and standards with the following exception. An exception is taken that instead of performing the main drain tests on all standpipes and rises, the main drain tests will be performed on 20 percent of all standpipes and risers.

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 are initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient enough to obstruct piping or sprinklers is detected, the material is removed, the source of the material is identified, and the source is corrected. Inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes for an adequate examination.

A.2.2.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The MNGP Outdoor and Large Atmospheric Metallic Storage Tanks AMP will manage the aging effects on the external and internal surfaces of condensate storage (CST) tanks, T-1A and T-1B. Each tank is a 230,000-gallon carbon steel insulated tank that sits on a concrete pad and soil. The tanks include preventive measures to mitigate corrosion. The tanks utilize an internal underwater epoxy coating system, an exterior coating system (i.e., primer), and caulking/sealant at the tanks to concrete interface to prevent moisture intrusion.

This AMP will manage loss of material by conducting one-time internal and periodic internal and external visual inspections. Inspections of caulking or sealant will be supplemented with physical manipulation. Thickness measurements of tank bottoms will be conducted to detect degradation (e.g., loss of material on the inaccessible external surface). The external surfaces of the insulated tanks will be sampled and inspected periodically.

Inspections and tests will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections and tests will follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

A.2.2.18 Fuel Oil Chemistry

The MNGP Fuel Oil Chemistry AMP is an existing AMP that manages loss of material in tanks, components, and piping exposed to an environment of diesel fuel oil. This AMP includes (a) surveillance and maintenance procedures to mitigate corrosion, and (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. This AMP includes periodic draining of accumulated water through tank bottom drains and periodic draining, cleaning, and internal visual inspection of the diesel oil storage tanks, day tanks, and base tanks. Volumetric examinations are used to assess identified degradation and to monitor for wall loss on internal surfaces of the tanks.

Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the MNGP Technical Specifications. Guidelines of ASTM Standards, including ASTM D 975 are also used when applicable. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining and cleaning of tanks and by verifying the quality of new fuel oil before it is introduced into the storage tanks.

The effectiveness of the fuel oil chemistry controls is verified by the MNGP One-Time Inspection AMP (Section A.2.2.20).

A.2.2.19 <u>Reactor Vessel Material Surveillance</u>

The MNGP Reactor Vessel Material Surveillance AMP is an existing condition monitoring program that monitors the loss of fracture toughness due to neutron embrittlement of the ferritic RPV beltline materials in a reactor coolant and neutron flux environment. The AMP utilizes surveillance capsules that are located near the inside wall of the RPV beltline region to duplicate, as closely as possible, the neutron spectrum, temperature history, and neutron fluence of the RPV inner surface. The fluence lead factor based on the location of the surveillance capsules allows them to achieve a neutron fluence exposure earlier than that of the RPV. Thus, the surveillance capsules can be withdrawn and tested prior to the RPV reaching the neutron fluence of interest.

The MNGP Reactor Vessel Surveillance Program is part of the Boiling Water Reactor's Vessel Internals Project (BWRVIP) Integrated Surveillance Program (ISP). MNGP committed to use the ISP in place of its existing surveillance programs, as indicated in the license amendment issued by the NRC regarding the implementation of the BWRVIP Reactor Pressure Vessel ISP (Reference ML030830591). For the SPEO, the program will be enhanced to implement BWRVIP-321-A and subsequent NRC approved revisions, upon NRC approval for MNGP to use BWRVIP-321-A, *Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR)* (Reference ML21152A086) to maintain compliance with 10 CFR Part 50, Appendix H.

The program provides sufficient material data and dosimetry to: (a) monitor irradiation embrittlement neutron fluences greater than the projected neutron fluence at the end of the SPEO, and (b) provide adequate dosimetry monitoring during the operational period. A surveillance capsule will be withdrawn and tested during the SPEO providing reactor vessel material irradiation embrittlement data corresponding to projected fluence at the end of 80 years of operation.

The program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in upper-shelf energy as a function of neutron fluence and irradiation temperature. 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 P-T limits evaluations). The Reactor Vessel Material Surveillance program is used in conjunction with the Neutron Fluence Monitoring (Section A.2.1.2) program.

Surveillance capsules are withdrawn, tested, and results reported in accordance with 10 CFR Part 50, Appendix H and ASTM E 185-82, to the extent practicable, for the configuration of the specimen in the capsule. Any changes to the surveillance capsule withdrawal schedule as part of the ISP must be approved by the NRC prior to implementation per 10 CFR Part 50, Appendix H. Specimens from tested capsules and withdrawn untested capsules are maintained in storage for possible reconstitution or re-insertion.

A.2.2.20 <u>One-Time Inspection</u>

The MNGP One-Time Inspection AMP is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action.

The elements of the MNGP One-Time Inspection AMP include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and OE, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the SPEO.

The MNGP One-Time Inspection AMP is used to verify the effectiveness of the MNGP Water Chemistry (Section A.2.2.2), Fuel Oil Chemistry (Section A.2.2.18), and Lubricating Oil Analysis (Section A.2.2.25) AMPs. For steel components exposed to water environments that do not include corrosion inhibitors as a preventive action (e.g., raw water and waste water) or steel components that do not have wall thickness measurement examinations conducted of a representative sample of each environment between the 50th and 60th year of operation, the program is used to verify that long-term loss of material due to general corrosion will not cause a loss of intended function (e.g., pressure boundary, leakage boundary (spatial), and structural integrity).

Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions.

A.2.2.21 <u>Selective Leaching</u>

The MNGP Selective Leaching AMP is an existing AMP that includes inspections of components that may be susceptible to loss of material due to selective leaching by demonstrating the absence of selective leaching (dealloying) of materials. The scope of this AMP includes components constructed of gray cast iron, ductile iron, and copper alloys (except for inhibited brass) containing greater than 15 percent zinc or greater than 8 percent aluminum in susceptible environments. One-time inspections for components exposed to a closed-cycle cooling water or treated water environment will be conducted, based on MNGP plant-specific OE which has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments. Visual inspections coupled with mechanical examination techniques such as chipping or scraping are conducted. Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, depth of dealloying, through-wall thickness, and chemical composition) are conducted for components exposed to raw water, waste water, soil, and groundwater environments. Inspections and tests will be conducted to determine whether loss of material will affect the ability of the components to perform their intended function for the SPEO. Inspections will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions.

Each of the one-time and periodic inspections for these material and environment populations comprises a 3 percent sample or a maximum of 10 components. For each material and environment population with 35 or more components, two destructive examinations will be performed in each 10-year inspection interval. For each population with less than 35 susceptible components, one destructive examination will be performed in each 10-year inspection interval.

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 SPEO, 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 for 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) did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria.

A.2.2.22 ASME Code Class 1 Small-Bore Piping

The MNGP ASME Code Class 1 Small-Bore Piping AMP is a new AMP that augments the existing ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping with a NPS diameter less than 4 inches and greater than or equal to 1 inch. This AMP is applicable to systems that have ASME Code Class 1 small-bore piping. This AMP provides a one-time volumetric inspection of a sample of this Class 1 piping and includes full penetration (butt) and partial penetration (socket) welds. The AMP includes measures to verify that degradation is not occurring, thereby confirming that the aging effects are being managed effectively. The MNGP ASME Code Class 1 Small-Bore Piping AMP includes locations that are susceptible to stress corrosion cracking and cracking due to thermal or vibratory fatigue loading. Such cracking is frequently initiated from the inside diameter (ID) of the piping; therefore, volumetric examinations are needed to detect cracks.

Volumetric inspections of a sample (sample size as specified in NUREG-2191, Table XI.M35-1) of small-bore Class 1 piping are performed to verify that cracking is not occurring during the SPEO. Per NUREG-2191, Table XI.M35-1, MNGP is a Category A plant because it has no history of age-related cracking. Per Category A, the inspection will be a one-time inspection with a sample size of 3 percent, up to a maximum of 10 welds, of each weld type, using a methodology to select the most susceptible and risk-significant welds. Destructive examination may be performed in lieu of volumetric examinations. Because more information can be obtained from a destructive examination than from nondestructive examination, credit will be taken for each weld destructively examined equivalent to having volumetrically examined two welds. Based on the results of these inspections, the need for additional inspections or programmatic corrective actions is then established.

A.2.2.23 External Surfaces Monitoring of Mechanical Components

The MNGP External Surfaces Monitoring of Mechanical Components AMP is an existing condition monitoring program, formerly the MNGP System Condition Monitoring Program, that manages loss of material, cracking, hardening or loss of strength (of elastomeric components), reduction of heat transfer due to fouling (air to fluid heat exchangers), loss of preload of HVAC closure bolting, and reduction of thermal insulation resistance due to moisture intrusion.

The MNGP External Surfaces Monitoring of Mechanical Components AMP also inspects the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces. This AMP provides for periodic visual inspection and examination for degradation of accessible surfaces of specific SSCs, and corrective actions, as required, based on these inspections.

Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) are conducted.

For certain materials, such as flexible polymers, manual and physical manipulation, or pressurization to detect hardening or loss of strength or reduction in impact strength is used to augment the visual examinations conducted under the MNGP External Surfaces Monitoring of Mechanical Components AMP. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are periodically inspected every 10 years during the SPEO.

Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures, including inspection parameters such as lighting, distance, offset, and surface coverage and presence of protective coatings.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

A.2.2.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new AMP that will manage loss of material, cracking, reduction of heat transfer due to fouling, flow blockage, hardening or loss of strength of polymeric materials, and wall thinning. Applicable environments will include air, gas, condensation, diesel exhaust, any water-filled systems, fuel oil, and lubricating oil.

The AMP will consist of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components. Internal surface examinations or ASME Code Section XI Visual Examination (VT)-1 examinations will be conducted to detect cracking of stainless steel and copper alloy (>15 percent Zn) components. Aging effects associated with items (except for elastomers) within the scope of the MNGP Open-Cycle Cooling Water AMP (Section A.2.2.11), the MNGP Closed Treated Water Systems AMP (Section A.2.2.12), and the MNGP Fire Water System AMP (Section A.2.2.16) are not managed by this AMP.

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. At a minimum, in each 10-year period during the SPEO a representative sample of 20 percent of the population or a maximum of 25 components per population (defined as components having the same combination of material, environment, and aging effect) will be inspected for the in-scope aging effects.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections will continue in each period despite meeting the sampling limit. 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. If visual inspection of internal surfaces is not possible, a plant-specific program will be used.

Internal visual inspections used to assess loss of material will be capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected for steel components exposed to raw water, raw water (potable), or wastewater, follow-up volumetric examinations will be performed.

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 will be such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria will be clear enough to reasonably assure a singular decision is derived based on observed conditions. Corrective actions will be performed as required based on the inspections results.

A.2.2.25 Lubricating Oil Analysis

The MNGP Lubricating Oil Analysis AMP is an existing program, previously known as the Lubrication Plan. The purpose of this AMP is to provide reasonable assurance that the oil environment in mechanical systems is maintained to the required quality to prevent or mitigate age-related degradation of components within the scope of the AMP. The MNGP Lubricating Oil Analysis AMP maintains lubricating oil system contaminants such as water and particulates within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Testing activities include sampling and analysis of lubricating oil for contaminants which could be indicative of in leakage and corrosion product buildup.

The effectiveness of the MNGP Lubricating Oil Analysis AMP will be validated by the results of inspections completed under the MNGP One-Time Inspection AMP (Section A.2.2.20).

A.2.2.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The MNGP Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is an existing condition monitoring program that periodically inspects and analyzes test coupons of the Boral material in the spent fuel storage racks to determine if the neutron-absorbing capability of the material has degraded over time. This program ensures that a 5 percent sub-criticality margin in the SFP is maintained during the period of extended operation (PEO) by monitoring for loss of material, changes in dimension, and loss of neutron-absorption capacity of the Boral material. This program consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., formation of blisters, pits, and bulges), and boron areal density as observed from coupons.

Information from MNGPs USAR Section 10.2.1 will be applicable for the Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP during the SPEO.

A.2.2.27 Buried and Underground Piping and Tanks

The MNGP Buried and Underground Piping and Tanks AMP, previously known as the Buried Piping and Tanks Inspection Program, is an existing AMP that manages the aging effects associated with the external surfaces of buried and underground piping and tanks such as loss of material and cracking. This AMP addresses piping and tanks composed of metallic (steel and stainless steel) materials that are within the scope of SLR in the CST, EDGs, ESW, fire water, off-gas, secondary containment, service and seal water, and wells and domestic water systems. Loss of material is monitored by visual inspection of the exterior surface and wall thickness measurements of the piping. Wall thickness is determined by a non-destructive examination technique such as UT.

This AMP also manages aging through preventive actions (e.g., coatings or wrapping, cathodic protection, and quality of backfill). Annual cathodic protection surveys are conducted. MNGP currently meets the conditions of Preventive Action Category F for inspections of buried steel piping, unless a reevaluation of cathodic protection system performance, future OE, or soil conditions determines that another preventive action category is more applicable. The number of inspections for each 10-year inspection period, commencing 10 years prior to the SPEO, are based on the effectiveness of the preventive actions above.

Visual inspections of external surfaces of buried components are performed to check for evidence of coating/wrapping damage, loss of material, and cracking. The selection of locations of these inspections will be based on plant OE and opportunities for inspection such as scheduled maintenance work; these inspections will occur once prior to the SPEO and at least every 10 years during the SPEO. 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 SPEO, an increase in the sample size is conducted.

A.2.2.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be a new AMP that will manage degradation of internal coatings/linings exposed to raw water, treated water, and air that can lead to loss of material of base metals or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. There are no internal coatings that require management by this program in a closed-cycle cooling water, waste water, or oil environment at MNGP. The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will not be used to manage loss of coating integrity for external coatings.

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will manage these aging effects for internal coatings by conducting opportunistic and periodic visual inspections of 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 CLB intended function(s). Where visual inspection of the coated/lined internal surfaces determines the coating/lining is deficient or degraded, physical tests will be performed, where physically possible, in conjunction with the visual inspection.

For tanks and heat exchangers, all accessible surfaces will be inspected. Piping inspections will be sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings will be conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist with the blisters being surrounded by sound material and with the size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. Additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment.

A.2.2.29 ASME Section XI, Subsection IWE

The MNGP ASME Section XI, Subsection IWE AMP is an existing AMP that was formerly known as the MNGP Primary Containment In-Service Inspection program. This condition monitoring AMP requires visual examinations of the accessible surfaces (base metal and welds) of the drywell, torus, vent lines, internal vent system, penetration assemblies and associated integral attachments. The program also requires examination of pressure retaining bolting and the drywell interior slab moisture barrier.

This program is in accordance with the requirements of ASME Section XI, Subsection IWE, and consistent with 10 CFR 50.55a, *Codes and Standards*, with supplemental recommendations. This AMP includes periodic visual, surface, and volumetric examinations, where applicable, for signs of degradation, damage, irregularities, and distress of coated areas due to degradation of the underlying metal shell. This AMP also includes corrective actions. General visual examinations that assess overall structural condition are performed once during each period as modified by 10 CFR 50.55a. Surface and/or volumetric examination augments visual examination as required to define the extent of observed conditions or to identify deterioration at inaccessible locations. Examinations are scheduled and performed as required to evaluate bolting when in place or disassembled, and the condition of the normally submerged torus surface. Acceptability of inaccessible areas of steel containment vessel is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

This AMP also includes aging management for the potential loss of material due to corrosion in the inaccessible areas of the MNGP Mark I steel containment. In addition, the AMP includes supplemental surface examinations to detect cracking on accessible portions of high-temperature drywell piping penetrations that are subject to cyclic loading but have no CLB fatigue analysis. If triggered by plant-specific OE, the AMP includes a one-time supplemental volumetric examination by sampling randomly-selected as well as focused locations susceptible to loss of thickness due to corrosion of the containment vessel that are inaccessible from one side. Inspection results are compared with prior recorded results in acceptance of components for continued service.

A.2.2.30 ASME Section XI, Subsection IWF

The MNGP ASME Section XI, Subsection IWF AMP is an existing AMP and part of the MNGP ASME Section XI In-Service Inspection program. Inspections provide for condition monitoring of Class 1, 2, 3, and MC component supports. Component supports are selected for inspection in accordance with the ASME code classification. The quantity of component supports selected for examination is increased as a result of discovered support deficiencies. The program is updated periodically as required by 10 CFR 50.55a.

This AMP consists of periodic visual examination of piping and component supports for signs of degradation, evaluation of the examination results, and corrective actions for any identified deficiencies. This AMP recommends additional inspections beyond the inspections required by ASME Code Section XI, Subsection IWF. This consists of a one-time inspection of an additional 5 percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection is conducted within 5 years prior to entering the SPEO. For high-strength bolting in sizes greater than 1-inch nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 should be performed to detect cracking in addition to the VT-3 examination.

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.

A.2.2.31 10 CFR Part 50, Appendix J

The MNGP 10 CFR Part 50, Appendix J AMP is an existing AMP that was formerly credited for initial license renewal. The MNGP 10 CFR Part 50, Appendix J AMP is a performance monitoring program that monitors leakage rates through the containment, including primary containment pressure-retaining boundary and individual penetration isolation barriers , penetrations, isolation valves, fittings, and other access openings, in order to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. This program is implemented in accordance with 10 CFR Part 50, Appendix J as modified by approved exemptions. The program is based on NEI 94-01 Revision 2-A with approved exceptions and is subject to the requirements of 10 CFR Part 54. Additionally, 10 CFR Part 50, Appendix J requires a general visual inspection of the accessible interior and exterior surfaces of the containment SCs to be performed prior to any Type A test and at periodic intervals between tests based on performance of the containment system.

A.2.2.32 Masonry Walls

The MNGP Masonry Walls AMP is an existing AMP that is currently implemented as part of the MNGP Structures Monitoring Program (Section A.2.2.33). This condition monitoring AMP is based on NRC Inspection and Enforcement (IE) Bulletin 80-11, *Masonry Wall Design*, and monitoring proposed by NRC Information Notice (IN) 87-67, *Lessons Learned from Regional Inspections of Licensee Actions in Response to IE 80-11*, for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained.

This AMP consists of periodic visual inspection of masonry walls within the scope of SLR to detect loss of material and cracking of masonry units and mortar. Masonry walls that are fire barriers are also managed by the Fire Protection program.

A.2.2.33 Structures Monitoring

The MNGP Structures Monitoring AMP is an existing AMP 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 described in ACI 349.3R, 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. Structures are monitored on an interval not to exceed 5 years. Inspections also include seismic joint fillers, elastomeric materials; steel edge supports, and bracings associated with masonry walls, and periodic evaluation of ground water chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with sufficient detail, such as photographs and surveys for the type, severity, extent, and progression of degradation, to ensure that corrective actions can be taken prior to a loss of intended function. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative evaluation criteria of ACI 349.3R.

A.2.2.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing AMP that is currently implemented as part of the MNGP Structures Monitoring Program. The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP was evaluated as a portion of the MNGP Systems and Structures Monitoring AMP in the initial license renewal application (LRA). The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is evaluated separately in the SLRA, and it is compared to the NUREG-2191, Section XI.S7 program. This condition monitoring AMP addresses age-related deterioration, degradation due to environmental conditions, and the effects of natural phenomena that may affect water-control structures.

The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP consists of inspection and surveillance of water control structures. The only structure within the scope of the MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is the INS. Parameters monitored are in accordance with RG 1.127 and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Inspections occur at least once every 5 years. Evaluation of ground water chemistry is performed under the scope of the MNGP Structures Monitoring AMP (Section A.2.2.33).

A.2.2.35 Protective Coating Monitoring and Maintenance

The MNGP Protective Coating Monitoring and Maintenance AMP is an existing AMP that ensures monitoring and maintenance of Service Level 1 coatings is implemented in accordance with Position C4 of RG 1.54, Revision 3, for the SPEO. The program consists of guidance for selection, application, inspection, and maintenance of protective coatings. The AMP will use the aging management detection methods, inspector qualifications, inspection frequency, monitoring, trending, and acceptance criteria defined in ASTM D 5163-08, *Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants*. The program addresses coatings applied to steel and concrete surfaces inside containment. Degraded coatings in the containment are assessed periodically to ensure post-accident operability of the Emergency Core Cooling System.

A.2.2.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, previously part of the Electrical Cables and Connections not Subject to 10 CFR 50.49 Environmental Qualification Requirements, is an existing AMP. This AMP applies to accessible non-EQ electrical cable and connection electrical insulation material within the scope of SLR subjected to an adverse localized environment (ALE) (e.g., heat, radiation, or moisture). An ALE is a condition in a limited plant area that is significantly more severe than the specified service environment for the component. ALEs are identified through the use of an integrated approach, which includes, but is not limited to, a review of relevant plant-specific and industry OE, field walkdown data, etc. Accessible non-EQ insulated cable and connections within the scope of SLR installed in ALEs are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination, that could indicate signs of reduced electrical insulation resistance. The first inspection for SLR is to be completed no later than six months prior to entering the SPEO. Recurring inspections are to be performed at least once every 10 years thereafter.

If visual inspections identify cable jacket and connection insulation surface anomalies, then testing may be performed. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. When a large number of cables and connections are identified as potentially degraded, a sample population is selected for testing. A sample of 20 percent of each cable and connection type with a maximum sample size of 25 is tested. The technical basis for the sample selection is documented.

When acceptance criteria are not met, a determination is made as to whether the surveillance, inspection, or tests, including frequency intervals, need to be modified.

Electrical insulation material for cables and connectors previously identified and dispositioned during the PEO as subjected to an ALE are evaluated for cumulative aging effects during the SPEO.

A.2.2.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirement used in Instrumentation Circuits

The MNGP Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program is an existing AMP. This AMP assures that non-EQ electrical cables and connections used in radiation monitoring and nuclear instrumentation circuits with sensitive, high-voltage, low-level signals that are within scope of license renewal and are installed in ALEs caused by heat, radiation and moisture maintain their intended functions through the SPEO.

Identification of electrical insulation aging effects for cables and connections is determined through evaluating calibration results or findings of surveillance testing programs to help identify the existence of aging effects. These aging effects are based on acceptance criteria related to instrumentation circuit performance. Reviews of calibration or surveillance results are performed at least once every ten years.

A.2.2.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible medium-voltage power cables (operating voltages of 2 kV to 35 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct-buried installations) non-EQ medium-voltage power cables within the scope of SLR exposed to wetting or submergence (i.e., 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), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that occurs for a limited time as drainage from either automatic or passive drains is not considered significant moisture for this AMP.

In-scope inaccessible medium-voltage power cables exposed to significant moisture will be tested to determine the condition of the electrical insulation. One or more tests may be required based on cable application, construction, and electrical insulation material to determine the age-related degradation of the cable insulation. The first tests for license renewal are to be completed no later than 6 months prior to the SPEO with subsequent tests performed at least once every six years thereafter.

Periodic actions to prevent inaccessible medium-voltage power cables from being exposed to significant moisture are performed. Periodic actions to mitigate inaccessible medium-voltage power cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduit ends, and removing water, as needed. Inspections will be performed periodically based on water accumulation over time and are performed at least once annually. Inspection frequencies will be adjusted based on inspection results, including plant-specific OE, but with a minimum inspection frequency of at least once annually. Inspections will also be performed after event-driven occurrences, such as heavy rain, ice and snow thaw, or flooding. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults, are effective in preventing inaccessible medium-voltage power cable exposure to significant moisture.

Inspection of manholes (if equipped) with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE.

A.2.2.39 <u>Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements</u>

The MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of the MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible I&C cables that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. The MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP applies to inaccessible (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) I&C cables that are within the scope of SLR 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), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This is a condition monitoring program. However, this AMP also includes periodic actions to prevent inaccessible I&C cables from being exposed to significant moisture. Periodic actions taken to mitigate inaccessible I&C cable exposure to significant moisture include inspection for water accumulation in cable manholes/vaults and conduit ends, and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain, or flooding. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults, is effective in preventing inaccessible I&C cable exposure to significant moisture.

Inspection of manholes (if equipped) with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE.

In addition to inspecting for water accumulation, visual inspections will be performed for I&C cables that are accessible during manhole inspections for jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the MNGP Inaccessible I&C Cables AMP uses the cable jacket material as representative of the aging effects experienced by the I&C cable electrical insulation. Inspection frequencies are adjusted based on inspection results, including plant-specific OE. The visual inspection of inaccessible I&C cables occurs at least once every six years and may be coordinated with the periodic inspection for water accumulation. Inaccessible (e.g., underground) I&C cables found to be exposed to significant moisture are evaluated to determine whether testing is required. If testing is warranted, initial cable testing is performed once on a sample population to determine the condition of the electrical insulation. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. One or more tests may be required due to cable type, application, and electrical insulation to determine the age-related degradation of the cable. Inaccessible and underground I&C cables designed for continuous wetting or submergence are also included in the MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP as a one-time inspection and test. The need for additional tests and inspections is determined by the test/inspection results, as well as industry and plant-specific OE.

Testing of installed inservice inaccessible (e.g., underground) I&C cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible I&C cables when testing is required in the MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

A.2.2.40 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible and underground low-voltage AC and DC power cables (i.e., typical operating voltage of less than 1,000 V, but no greater than 2 kV) that are not subject to EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. This AMP applies to inaccessible and underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR exposed to significant moisture. In-scope inaccessible and underground low-voltage power cable splices subjected to wetting or submergence are also included within the scope of 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. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this AMP.

This is a condition monitoring program. However, the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP also includes periodic actions to mitigate inaccessible low-voltage power cable exposure to significant moisture include inspections for water accumulation in cable manholes/vaults and conduit ends and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspections occur at least once annually with the first inspections for SLR completed prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain, rapid thawing of ice or snow, flooding. Inspection frequencies are adjusted based on inspection results including plant-specific OE. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults, is effective in preventing inaccessible low-voltage power cable exposure to significant moisture.

Inspection of manholes (if equipped) with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE.

In addition to inspecting for water accumulation, visual inspections will be performed for low-voltage cables that are accessible during manhole inspections for jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The visual inspection portion of the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP uses the jacket material as representative of the aging effects experienced by the low-voltage power cable insulation. The visual inspection of underground low-voltage power cables occurs at least once every 6 years and may be coordinated with the periodic inspections for water accumulation. Inaccessible and underground low-voltage power cables found to be exposed to significant moisture are evaluated to determine whether testing is required. If testing is required, initial testing is performed once on a sample population to determine the condition of the electrical insulation. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. One or more tests may be required based on cable type, application, and electrical insulation material to determine the age-related degradation of the cable insulation. Inaccessible low-voltage power cables designed for continuous wetting or submergence are also included in this AMP. The need for additional periodic tests and inspections is determined by the test/inspection results as well as industry and plant-specific OE.

Testing of installed inservice inaccessible (e.g., underground) low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or instrumentation and control (I&C) cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is required in the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

A.2.2.41 Metal-Enclosed Bus

The MNGP Metal-Enclosed Bus AMP is an existing condition monitoring program currently known as the Bus Duct Inspection Program. This AMP manages the age-related degradation effects for electrical bus bar bolted connections, bus bar electrical insulation, bus bar insulating supports, bus enclosure assemblies (internal and external), and elastomer components (e.g., gaskets, boots, and sealants). This program does not manage the aging effects on external MEB surfaces or structural supports, which are managed under the MNGP Structures Monitoring AMP. The first inspection for SLR will be completed prior to the SPEO and every 10 years thereafter.

MEB bolted bus connections are tested on a sampling basis to ensure the connections are not experiencing increased resistance due to loosening of bolted bus duct connections caused by repeated thermal cycling of connected loads by measuring connection resistance using a micro ohmmeter or performing thermography. A sample of 20 percent with a maximum sample of 25 constitutes a representative bolted bus connection sample size. In addition to resistance measurement or thermography, bolted connections not covered with heat shrink tape or boots are visually inspected for increased resistance of connection (e.g., loose or corroded bolted connections and hardware including cracked or split washers). Resistance testing or thermography of the internal bus connections are performed on a frequency not to exceed 10 years.

As an alternative to measuring connection resistance of bolted connections, for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., visual inspection of insulation material to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination may be performed. If the alternative visual inspection is used to check MEB bolted connections, the first inspection will be performed prior to the SPEO and every 5 years thereafter.

A.2.2.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing AMP. This AMP provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the EQ requirements of 10 CFR 50.49 and susceptible to age-related degradation resulting in increased resistance are maintained consistent with the CLB through the SPEO.

This AMP manages the aging mechanisms and effects that result in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation of the metallic portions of electrical cable connections within the scope of SLR.

This AMP focuses on the metallic parts of the electrical cable connections. Wiring connections internal to an active assembly are considered part of the active assembly and therefore are not within the scope of this AMP. This program does not apply to high voltage (>35 kV) switchyard connections. Cable connections covered under the Environmental Qualification of Electric Equipment program are not included in the scope of this program.

One-time testing, on a representative sample of each type of non-EQ electrical cable connections within the scope of SLR, is performed prior to the SPEO. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. The specific type of test performed will be determined prior to the initial test and will be a proven test for detecting loose connections, such as thermography, contact resistance testing, or other appropriate testing. The findings of the initial one-time test are evaluated to demonstrate that either aging of metallic cable connections is not occurring and/or that the existing preventive maintenance program is effective. One-time testing provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. Depending on the findings of the one-time test, subsequent testing may have to be performed (on a recurring basis) within 10 years of initial testing. The following factors are considered for sampling: voltage level (medium and low voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. The first tests and evaluation of results for SLR are to be completed prior to the SPEO.

As an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials may be used to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO and at least every 5 years thereafter. The basis for performing only a periodic visual inspection, if selected, will be documented.

A.3 Time-Limited Aging Analyses

With respect to plant TLAA, 10 CFR 54.21(c) states the following:

(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.

This section discusses the evaluation results for each of the plant-specific TLAAs performed for SLR. The evaluations have demonstrated that the analyses remain valid for the SPEO; that the analyses have been projected to the end of the SPEO; or that the effects of aging on the intended function(s) will be adequately managed for the SPEO. The TLAAs, as defined in 10 CFR 54.3, are listed in Section A.3.2 through, and including, Section A.3.6.3 and are evaluated per the requirements of 10 CFR 54.21(c).This section discusses the evaluation results for each of the MNGP TLAA performed for SLR. The evaluations have demonstrated that the analyses remain valid for the SPEO; that the analyses have been projected to the end of the SPEO; or that the effects of aging on the intended function(s) will be adequately managed for the SPEO. The TLAA, as defined in 10 CFR 54.3, are listed in Section A.3.2 through, and including, Section A.3.6 and are evaluated per the requirements of 10 CFR 54.21(c).

A.3.1 Identification of Time-Limited Aging Analyses Exemptions

10 CFR 54.21(c)(2) states the following with respect to TLAA exemptions:

A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

A search of docketed correspondence, the operating license, and the Updated Safety Analysis Report (USAR) was performed to identify the active exemptions currently in effect pursuant to 10 CFR 50.12. These exemptions were then reviewed to determine whether the exemption was based on a TLAA. No 10 CFR 50.12 exemptions involving a TLAA, as defined in 10 CFR 54.3, were identified for MNGP. This addresses the 10 CFR 54.21(c)(2) exemptions list requirement.

A.3.2 Reactor Vessel Neutron Embrittlement

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, P-T limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR Part 50, Appendices G and H. The MNGP Reactor Vessel Material Surveillance AMP is described in Section A.2.2.19.

The ferritic materials of the reactor vessel are subject to embrittlement due to high energy (E >1.0 MeV) neutron exposure. Neutron embrittlement means the material has lower toughness (i.e., will absorb less strain energy during a crack or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant). This group of TLAA concerns the effect of irradiation embrittlement (IE) on the beltline and extended beltline regions of the MNGP reactor vessel, and how this mechanism affects analyses that provide operating limits or address regulatory requirements.

Neutron fluence is used to calculate parameters for embrittlement analyses that are part of the CLB and support safety determinations, and since these analyses are calculated based on plant life, they have been identified as TLAA, as defined in 10 CFR 54.21(c). Therefore, the following TLAAs were evaluated for the increased neutron fluence associated with 80 years of operations:

- Neutron fluence projections (Section A.3.2.1)
- RPV Materials USE Reduction Due to Neutron Embrittlement (Section A.3.2.2)
- Adjusted Reference Temperature (ART) for RPV Materials Due to Neutron Embrittlement (Section A.3.2.3)
- RPV Thermal Limit Analysis: Operating P-T Limits (Section A.3.2.4)
- RPV Circumferential Weld Examination Relief (Section A.3.2.5)
- RPV Axial Weld Failure Probability (Section A.3.2.6)
- Reflood Thermal Shock Analysis of the RPV (Section A.3.2.7)
- Reflood Thermal Shock Analysis of the RPV Core Shroud (Section A.3.2.8)
- Loss of Preload for Core Plate Rim Holddown Bolts (Section A.3.2.9)
- Susceptibility to IASCC (Section A.3.2.10)

A.3.2.1 <u>Neutron Fluence Projections</u>

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter that contact the RPV internals and shell. These fluence projections have been used as inputs to the neutron embrittlement analyses that evaluate the reduction of fracture toughness aging effect.

The EFPY projections through the end of the SPEO for a unit is the sum of the accumulated EFPY and the projected future EFPY. The projected 80-year EFPY for MNGP is 72 EFPY.

Updated fluence projections were developed for 80 years of plant operation, based upon 72 EFPY for use as inputs to updated neutron embrittlement analyses for the SPEO. The 72 EFPY fluence projections were developed using methodologies that follow the guidance of NRC RG 1.190 and is consistent with the NRC approved

RAMA methodology described in MNT-FLU-001-R-001. The 72 EFPY fluence projections have been determined for reactor vessel beltline and extended beltline materials, which include all reactor vessel forgings, plate material, and welds that are projected to be exposed to 1.0 x 10^{17} neutrons/cm^2 (n/cm^2) or more during 80 years of operation. While there are no regulatory requirements comparable to RG 1.190 that provide guidance for determining fast neutron fluence in RVI components, the NRC has issued a safety evaluation providing conditional approval to use the RAMA Fluence Methodology for determining fluence in BWR top guide and core shroud components. The neutron fluence projections have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

The MNGP Neutron Fluence Monitoring AMP and Reactor Vessel Material Surveillance AMP ensure the continued validity and adequacy of projected neutron fluence analyses and related neutron fluence-based TLAAs as described in Sections A.2.1.2 and A.2.2.19, respectively.

A.3.2.2 RPV Materials Upper Shelf Energy (USE) Reduction Due to Neutron Embrittlement

Upper-shelf energy (USE) is the parameter used to indicate the toughness of a material at elevated temperature. There are two sets of rules that govern USE acceptance criteria. 10 CFR Part 50, Appendix G, Paragraph IV.A.1.a, states that RPV beltline materials must have Charpy USE of no less than 75 ft-lb initially and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of ASME Code, Section XI.

The CLB upper-shelf energy (USE) calculations were prepared for the RPV beltline and extended beltline materials for 54 EFPY. Since the USE value is a function of neutron fluence which is associated with a specified operating period, the USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

An Equivalent Margin Analysis (EMA) has been performed for the limiting beltline plate and weld materials for 80 years of operation at 72 EFPY, and then compared against the RG 1.99 predicted percent USE decrease for the surveillance plate heat C2220. These evaluations demonstrate that EOL USE values for the MNGP beltline materials remain bounded by the EMA evaluation and remain within the limits of RG 1.99 and satisfy the margin requirements of 10 CFR 50 Appendix G for at least 72 EFPY of operation.

Therefore, the EMAs have been projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.2.3 Adjusted Reference Temperature (ART) for RPV Materials Due to Neutron Embrittlement

10 CFR Part 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}) means that higher temperatures are required for the material to continue to act in a ductile manner.

The adjusted reference temperature (ART) of the limiting beltline or extended beltline material is used to adjust the beltline pressure-temperature (P-T) limit curves to account for irradiation effects. RG 1.99 provides the methodology for determining the ART of the limiting material. The initial nil ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. Neutron irradiation increases the RT_{NDT} beyond its initial value.

10 CFR Part 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}) means that higher temperatures are required for the material to continue to act in a ductile manner. Since the ΔRT_{NDT} value is a function neutron fluence, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for the 80-year SPEO.

The ART analyses have been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.2.4 RPV Thermal Limit Analysis: Operating P-T Limits

10 CFR Part 50 Appendix G requires that the RPV be maintained within established P-T limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RPV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RPV fluence effect on fracture toughness.

The current heatup and cooldown curves were calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline and extended beltline regions of the reactor vessel for 54 EFPY. In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the SPEO need not be submitted as part of the SLRA since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process for P-T limits that are located in the Pressure and Temperature Limits Report (PTLR). The 10 CFR 50.90 process will ensure that the P-T limits for the SPEO will be updated prior to expiration of the P-T limits for the current period of operation.

The P-T limit curves will be updated, and a Technical Specification change request will be submitted for approval prior to exceeding the current 54 EFPY limit. The Reactor Vessel Material Surveillance AMP (Section A.2.2.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval, as required, prior to exceeding the current terms of applicability.

A.3.2.5 RPV Circumferential Weld Examination Relief

MNGP has previously applied for and been granted relief from RPV circumferential weld inspections. The relief from inspection is based on assessment of the probability of failure of the limiting circumferential weld. This assessment is based on 54 EFPY fluence values associated with 60 years of operation and has therefore been identified as a TLAA requiring evaluation for the SPEO.

BWRVIP-329-A and the associated NRC safety evaluation report (SER) provide 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. BWRVIP-329-A provides criteria for applicability based on plant-specific data. Evaluation for applicability to MNGP confirms that the RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the MNGP RPV meets the applicability criteria of BWRVIP-329-A. As such, on the technical basis of BWRVIP-329-A and as stated in the BWRVIP-329-A SER, MNGP is justified for request for alternative pursuant to 10 CFR 40.40(a)(z)(1) from the ASME Code, Section XI examinations for RPV circumferential weld for up to 80 years of plant operation. 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.3.2.6 RPV Axial Weld Failure Probability

The BWRVIP recommendations for inspection of reactor pressure vessel shell welds in BWRVIP-05P include examination of 100 percent of the axial welds and inspection of the circumferential welds only at the intersections of these welds with the axial welds. The NRC provided separate conditional failure probability assessments in the Supplement to the Final Safety Evaluation of the BWRVIP-05 Report, dated March 7, 2000, and calculated a RPV failure frequency of 5.02E-06 due to failure of limiting axial welds in the BWR fleet. Since these NRC failure probability assessments are applicable to MNGP, they are identified as TLAAs requiring evaluation through the SPEO.

BWRVIP-329-A and the associated NRC SER provide 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. BWRVIP-329-A provides criteria for applicability based on plant-specific data. Evaluation for applicability to MNGP confirms that the RPV dimensions are within the limits of the enveloping RPV dimensions in BWRVIP-329-A.

Using plant-specific data for the RPV dimensions and limiting ARTs for the RPV plates and welds, the evaluation shows that the MNGP RPV meets the applicability criteria of BWRVIP-329-A. As such, on the technical basis of BWRVIP-329-A and as stated in the BWRVIP-329-A SER, MNGP is justified for acceptable embrittlement of RPV axial welds for up to 80 years of plant operation.

Therefore, this analysis has been projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.2.7 Reflood Thermal Shock Analysis of the RPV

10 CFR 50 Appendix A, General Design Criterion 31 requires that the reactor coolant pressure boundary of a light water reactor be designed such that it possesses adequate margin against non-ductile failure for all postulated conditions. For boiling water reactors (BWRs), this requirement is historically demonstrated both by development of P-T Limit Curves, which are addressed in Section A.3.2.4, and by reference to a generic fracture mechanics analysis that evaluates the effects of the limiting Loss of Coolant Accident (LOCA) event.

For all beltline materials, a bounding evaluation was performed in which the limiting stresses and material properties for the MNGP RPV were used. The beltline shells (plates and welds) and the beltline nozzles were considered separately. To be consistent with previous analyses, RPV integrity is assured by fracture mechanics analyses of the limiting vessel locations to show no crack initiation would occur under these LOCA transient conditions for the SPEO. The limiting 0T ART for beltline plates and welds at 72 EFPY, corresponding to ISP plate heat number C2220-2 (present in the lower and intermediate shell) is 197.8°F.

The maximum crack driving force in the vessel at any time during the transient is 105 ksi√in. Therefore, the static initiation fracture toughness does not exceed this crack driving force by any margin of 1.35. These results demonstrate that a postulated flaw in the vessel would be stable with respect to nonductile fracture following a main steam line rupture.

Further, the thermal stress evaluation determined the peak stress intensity factor, K, at 1/4T has a value of approximately 100 ksi√in. A maximum K_I of 105 ksi√in was utilized per Section XI IWB-3612. The acceptability of this K on a plant-specific basis for MNGP can be determined by considering a revised allowable fracture toughness applicable to the MNGP vessel for 72 EFPY. Based on a 0T ART of 197.8°F, the fracture toughness K_{IC} of 174.4°F is above the upper shelf value of 200 ksi√in.

The bounding stress intensity factor, K, for MNGP of 105 ksi√in is less than the available fracture toughness of 200 ksi√in after 72 EFPY, which provides an acceptable result for reshock of the vessel reflood from a main steam line break.

The reactor pressure vessel reflood thermal shock analysis has been projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.2.8 Reflood Thermal Shock Analysis of the RPV Core Shroud

Neutron irradiation embrittlement may affect the ability of reactor vessel core shroud to withstand a low-pressure coolant injection thermal shock transient. The reactor vessel core shrouds, which were fabricated from Type 304 stainless steel, have been analyzed for a low-pressure coolant injection reflood thermal shock transient considering the embrittlement effects of neutron irradiation exposure. The core shroud receives the maximum irradiation on the inside surface approximately opposite the midpoint of the fuel centerline.

The maximum thermal shock stress in this region is equivalent to 0.57 percent strain. This strain range of 0.57 percent was calculated at the midpoint of the shroud, the zone of highest neutron irradiation. The calculated strain range of 0.57 percent represents a considerable margin of safety relative to measured values of percent elongation for annealed Type 304 stainless steel irradiated to 8 x 10^{21} n/cm^2 (E >1 MeV). This analysis has been identified as a TLAA requiring evaluation for the SPEO.

The fluence for the most irradiated point on the core shroud was calculated to be 5.68 x 10^{21} n/cm^2 (E >1 MeV) for 80 years. This can be compared to the test data for control blade handles at 8 x 10^{21} n/cm^2 (E >1 MeV) described in BWRVIP-66. The lowest measured value of percent elongation for stainless steel weld metal is 4 percent for a temperature of 297°C (567°F) with a neutron fluence of 8 x 10^{21} n/cm^2 (E >1 MeV), while the average value of base metal at 290°C (554°F) is 20 percent.

Since the most irradiated point on the core shroud for 80 years of operation is calculated to be 5.68 x 10^{21} n/cm^2 (E >1 MeV), below the 8 x 10^{21} n/cm^2 fluence threshold for which elongation test data are available, the measured value of elongation bounds the calculated thermal shock strain amplitude of 0.57 percent. The calculated thermal shock strain at the most irradiated location is acceptable considering the loss of ductility effects for an 80-year operating period. Therefore, this analysis has been projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.2.9 Loss of Preload for Core Plate Rim Holddown Bolts

The RPV core plate is attached to the core support structure by stainless steel holddown bolts arranged along the rim of the plate. These bolts are subject to stress relaxation (loss of preload) due to irradiation effects. An analysis was performed concluding that a reduction in preload as high as 19 percent over the 40-year life of the bolts is acceptable to meet design requirements. A subsequent reevaluation determined that this maximum relaxation value of 19 percent is applicable to an average fluence value of 8.0 x 10^{19} n/cm^2 over the entire length of the bolt located at the azimuthal location with peak fluence. These analyses were identified as TLAAs.

Generic assessment can be performed regarding stress relaxation of fasteners relative to retained preload in operation. The BWRVIP conducted thorough bounding analyses to justify the elimination of core plate bolt examinations. Because of the inaccessibility of these components, inspection is often difficult for applicants to pursue. Guidance on the elimination of these inspections and the management of aging of these components is contained within BWRVIP-25, Revision 1-A.

An assessment was performed to confirm that the MNGP Core Plate Bolts can have inspections waived and have their age-related degradation managed for the SPEO for 72 EFPY. This evaluation concluded that the criteria of Appendix I of BWRVIP-25, Revision 1-A to justify the elimination of core plate bolt inspections at MNGP are satisfied. Therefore, elimination of core plate bolt inspections at MNGP for the SPEO is justified. The loss of preload for core plate rim holddown bolts have been satisfactorily projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.2.10 Susceptibility to IASCC

MNGPs LRA presents a fluence threshold value of 5.0 x 10^{20} n/cm^2 beyond which IASCC and embrittlement may occur in BWR vessel internal components. The LRA concluded that top guide, core shroud, and incore instrumentation dry tubes and guide tubes are susceptible to IASCC for the PEO and concludes that aging management is required through the first PEO. Since this analysis was performed for 60 years, this analysis has been identified as a TLAA that requires evaluation for the SPEO.

Fluence values for the core shroud, top guide, and jet assembly components are projected to exceed the threshold of 5.0x10^{20} n/cm^2 before the end of the SPEO. Therefore, the core shroud, top guide, and jet assembly components will be inspected periodically for cracking and loss of fracture toughness (embrittlement) during the SPEO in accordance with the BWR Vessel Internals (Section A.2.2.7) AMP.

The effects of aging on the intended function(s) of the core shroud, top guide, and jet assembly components will be adequately managed through the SPEO by the BWR Vessel Internals (Section A.2.2.7) program, in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.3 Metal Fatigue

Fatigue is an age-related degradation mechanism caused by cyclic stressing of a component by either mechanical or thermal stresses. The thermal and mechanical fatigue analyses of plant mechanical components have been identified as TLAAs for MNGP. Specific components have been designed considering transient cycle assumptions, as listed in vendor specifications and the USAR. Fatigue analyses are considered TLAA for Class 1 and non-Class 1 mechanical components requiring evaluation for the SPEO in accordance with 10 CFR 54.21(c).

The following metal fatigue evaluations are documented in the following sections:

- 80-Year Transient Cycle Projections (Section A.3.3.1)
- ASME Section III, Class 1 Fatigue Waivers (Section A.3.3.2)
- RPV Fatigue Analyses (Section A.3.3.3)
- Fatigue Analysis of RPV Internals (Section A.3.3.4)
- ASME Section III, Class 1 (Section A.3.3.5)
- ASME Section III, Class 2 and 3 and ANSI B31.1 (Section A.3.3.6)
- Environmentally-Assisted Fatigue (Section A.3.3.7)

A.3.3.1 80-Year Transient Cycle Projections

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 SPEO is required to demonstrate that the analyses remain valid.

Projections of the transient cycles through the SPEO 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 cycles, CUF values, and CUF_{en} values have been projected through the SPEO.

A.3.3.2 ASME Section III, Class 1 Fatigue Waivers

Original components of the MNGP RPV were designed to the ASME Boiler and Pressure Vessel Code, 1965 Edition with Addenda through Summer 1966. The in-core detector assembly was designed to the 1971 Edition with Addenda through Summer 1973. Specific editions are not given for the IRM/SRM (intermediate range monitor/source range monitor) dry tube or the power range detector, but the paragraph numbering indicates that these were designed to the 1971 Edition or later.

The design stress reports for the MNGP RPV include fatigue waivers that determined that some RPV components did not require explicit fatigue analyses because the criteria from ASME Section III, Paragraph N-415.1 or NB-3222.4(d) were satisfied. The fatigue waivers were reevaluated for SPEO in accordance with the applicable ASME Section III, Paragraph N-415-1 criteria.

All components reviewed in this reevaluation were found acceptable regarding fatigue usage for 80 years, including effects of rerate and EPU. The ASME Section III Class 1 fatigue waiver acceptance criterion continues to be satisfied based on 80-year projected transient cycles through the SPEO. The ASME Code, Section III, Class 1 component fatigue waivers will be managed by the Fatigue Monitoring (A.2.1.1) AMP through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii). The Fatigue Monitoring (A.2.1.1) AMP will monitor the transient cycles which are the inputs to the fatigue waiver reevaluations and require action prior to exceeding design limits that would invalidate their conclusions.

A.3.3.3 RPV Fatigue Analyses

The RPV was originally designed for the initial 40-year license period in accordance with the ASME Code Section III, its interpretations, and applicable requirements, (including 1965 Summer Addenda) for Class 1 design requirements per USAR, Table 4.1-1. The RPV Class 1 fatigue analyses determined the effects of transient cyclic loadings resulting from changes in system temperature and pressure and for seismic loading cycles. The fatigue analyses evaluated explicit numbers and types of transients that were postulated for the 40-year operating period of the plant. These Class 1 fatigue analyses were required to demonstrate that the Cumulative Usage Factor (CUF) for each component will not exceed the design limit of 1.0 for all the postulated transients.

The fatigue analyses and corresponding CUF for all MNGP RPV locations will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (Section A.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.3.4 Fatigue Analysis of RPV Internals

Fatigue analysis of the RPV internals (RVI) was performed for MNGP's initial LR using the ASME Boiler and Pressure Vessel Code, Section III, as a guide. The most significant fatigue loading occurs at the jet pump diffuser to baffle plate weld location; therefore, this location is bounding for all other fatigue affected components in the RVI.

In the initial analysis of this location, maximum strain occurred after a recirculation line break causing the RPV water level to drop, exposing the jet pump assembly to 540°F steam; the concurrent pressure drop results in LPCI injection at 120°F. Based on this description, this is the same event as the design basis accident (DBA) used in the reanalysis. Given that a DBA is not expected to occur at all during the plant life, 1 cycle of DBA is still bounding for 80 years.

Therefore, the MNGP analysis for fatigue-affected RVI components remains valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

A.3.3.5 ASME Section III, Class 1

MNGP piping systems were originally designed in accordance with ASA B31.1 and USAS B31.1.0 which did not require that an explicit fatigue analysis be performed. Reconciliation for the use of later editions of construction codes for modification to or replacement of piping and components had been performed in accordance with Section IWA-7210(c), Section XI of the ASME Code. The governing code for design, materials, fabrication and erection of piping, piping components, and pipe support modifications or replacements is ANSI B31.1, 1977 Edition including Addenda up to and including the Winter of 1978.

For the locations within the scope of this analysis, existing fatigue tables and 80-year cycle projections are used to calculate 80-year fatigue usage. If needed, fatigue tables are adjusted for rerate and/or extended power uprate (EPU) based on changes to temperature, pressure, and flow rate. The ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition with Addenda through Summer 1982 is used.

The fatigue analyses and corresponding CUF for MNGP ASME Class 1 locations will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed in accordance with ASME Section III, Class 1 requirements will be managed by the Fatigue Monitoring AMP (Section A.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.3.6 ASME Section III, Class 2 and 3 and ANSI B31.1

The MNGP non-Class 1 Reactor Coolant System (RCS) piping and balance-of-plant piping systems within the scope of SLR are designed to the requirements of the ANSI B31.7 and ANSI B31.1 Codes. Piping and components designed in accordance with these Codes are not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in a simplified manner in the design process. These non-Class 1 piping Codes first require prediction of the overall number of thermal and pressure cycles expected during the lifetime of these components. Then a stress range reduction factor is determined for that number of cycles using a table from the applicable design code. If the total number of cycles is 7,000 or less, the stress range reduction factor is 1.0, which when applied, would not reduce the allowable stress value.

A review of the ANSI B31.7 and ANSI B31.1 piping within the scope of SLR was performed in order to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Non-Class 1 components are excluded from the scope of this evaluation if they are in systems that may have normal/upset condition operating temperature that do not exceed 220°F. This is based on recommended values of 220°F for carbon steel or 270°F for austenitic stainless steel in the EPRI Fatigue Management Handbook. Piping & Instrument Diagrams (P&IDs) were used to identify affected systems for this evaluation.

The current Class 2/3 piping fatigue design criteria remain valid with significant margin for the 80 year SPEO. Therefore, all of these systems at MNGP are suitable for extended operation without further evaluation and can be dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A.3.3.7 <u>Environmentally-Assisted Fatigue</u>

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on cumulative usage factor (CUF_{en}) must be examined for a set of sample critical components for the plant. These critical components should include those listed in NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components* and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. Any additional limiting locations are identified through an environmentally-assisted fatigue (EAF) screening evaluation. The EAF screening process evaluates existing CLB fatigue usage values for the ASME Code, Section III and NUREG/CR-6260 equipment and piping components, to determine the lead indicator (also referred to as sentinel) locations for EAF.

Using bounding F_{en} values based on material type, maximum temperature, and dissolved oxygen, bounding EAF usage (U_{en}) is estimated for all locations. Locations that have bounding U_{en} <1.0 are screened out. A location that is screened out must have an analysis with a similar or lower level of detail as the location that is potentially screening it out. The results for MNGP were 6 NUREG/CR-6260 locations and four (4) additional locations that may be more limiting than these locations.

The effects of environmentally-assisted fatigue on the intended functions of all screened ASME Code, Section III and NUREG/CR-6260 component locations have been shown to be maintained with usage factors less than 1.0 through the SPEO. The effects of EAF on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (Section A.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.4 Environmental Qualification (EQ) of Electrical Equipment

Thermal, radiation, and cyclical aging analyses of plant electrical and instrumentation components, developed to meet 10 CFR 50.49 requirements, have been identified as TLAA. The NRC has established EQ requirements in 10 CFR 50.49 and 10 CFR Part 50, Appendix A, Criterion 4. 10 CFR 50.49 specifically requires that an Environmental Qualification of Electric Equipment 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 LOCA, HELB, or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations for electrical components in the Environmental Qualification of Electric Equipment program that specify a qualification of at least 60 years have been identified as TLAA for license renewal because the criteria contained in 10 CFR 54.3 are met.

The MNGP Environmental Qualification of Electric Equipment AMP (Section A.2.1.3) 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 components within the scope of the program, 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 during their service lives.

10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e)(5) also requires replacement or refurbishment of components prior to the end of designated life unless additional life is established through reanalysis or ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions. 10 CFR 50.49(k) and (l) permit different qualification criteria to apply based on plant and component vintage. Supplemental EQ regulatory guidance for compliance with these different qualification criteria is provided in Division of Operating Reactors Guidelines, NUREG-0588, and NRC RG 1.89, Revision 1.

The MNGP Environmental Qualification of Electric Equipment AMP (Section A.2.1.3) will manage the effects of aging for the components associated with the EQ TLAA. This program implements the requirements of 10 CFR 50.49 (as further defined and clarified by NUREG-0588 and RG 1.89, Revision 1). Component aging evaluations are reanalyzed on a routine basis to extend the qualifications of components. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The reanalysis of an aging evaluation could extend the qualification of the component. 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 MNGP Environmental Qualification of Electric Equipment AMP (Section A.2.1.3) has been demonstrated to be capable of programmatically managing the aging of the electrical and instrumentation components in the scope of the program. Therefore, aging will be adequately managed for the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.5 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses

A.3.5.1 Fatigue Analysis of the Suppression Chamber, Vents, and Downcomers

Hydrodynamic loads were updated subsequent to the original design for the containment suppression chamber vents. These loads result from blowdown into the suppression chamber during a postulated LOCA and during SRV operation for plant transients. The results of analyses of these effects are presented in the MNGP USAR. Consequently, these analyses are TLAAs.

The limiting fatigue location for the suppression chamber, vents and downcomers is the vent header-downcomer intersection. The bounding usage values for the vent system for 80 years include 699 SRV discharges under a normal operating condition and 74 SRV discharges under a small break accident.

The fatigue analyses and corresponding CUF for MNGP Suppression Chamber, Vents, and Downcomers locations will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (Section A.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.5.2 Fatigue Analysis of the Safety Relief Valve (SRV) Discharge Piping Inside the Suppression Chamber and Internal Structures

The Plant Unique Analysis Report (PUAR) describes the fatigue analysis of the SRV discharge lines. These analyses assume a limited number of SRV actuations throughout the life of MNGP and are therefore TLAAs.

Fatigue usage was calculated for normal operating condition plus DBA and normal operating condition plus small/intermediate break accident with 50 SRV actuations postulated during accident conditions and 934 SRV actuations postulated during normal operating conditions for a total of 984 postulated SRV actuations.

The fatigue analyses and corresponding CUF for MNGP SRV discharge piping inside the suppression chamber will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (Section A.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.5.3 Fatigue Analysis of Suppression Chamber External Piping and Penetrations

These analyses include the large and small bore torus attached piping, suppression chamber penetrations and the ECCS suction header. Fatigue analyses were completed that were based on cycles postulated to occur within the operating life of the plant. Therefore, these calculations are TLAAs.

The SRV discharge piping was identified as the most limiting of torus attached piping. The SRV piping therefore bounds all other torus attached piping. 934 SRV actuations under normal operating conditions were assumed in the design basis and 258 of the 934 were multiple SRV actuations. 699 SRV actuations have been projected to occur at 80 years. Of the 699 projected SRV lifts, 506 are taken as single SRV lifts and 193 are taken as multiple SRV lifts. The ratio is consistent with the original design which had 676 single SRV lifts and 258 multiple SRV lifts.

The fatigue analyses and corresponding CUF for MNGP Suppression Chamber External Piping and Penetrations locations will remain less than 1.0 during the SPEO. The effects of fatigue on the intended functions of components analyzed will be managed by the Fatigue Monitoring AMP (Section A.2.1.1) through the SPEO in accordance with 10 CFR 54.21(c)(1)(iii).

A.3.5.4 Drywell-to-Suppression Chamber Vent Line Bellows Fatigue Analysis

The drywell-to-suppression chamber vent line bellows are included in the Mark I Containment Long Term Program plant-unique analysis. A fatigue analysis of the vent line bellows demonstrates their adequacy to accommodate thermal and internal pressure load cycles for the life of the plant. As such this analysis is a TLAA.

The drywell to suppression chamber vent line bellows fatigue analysis conservatively considered 300 startup/shutdown cycles and 1 cycle due to postulated accident conditions with a resulting usage of 0.10. Since 203 startup/shutdown cycles are projected for 80-years of operation, the previous analysis is conservative, and the usage is acceptable for 80-years.

The drywell-to-suppression chamber vent line bellows fatigue analysis remain valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

A.3.5.5 Primary Containment Process Penetration Bellows Fatigue Analysis

Containment pipe penetrations that are required to accommodate thermal movement have expansion bellows. The bellows are designed for a minimum number of operating cycles over the design life of the plant. Consequently, the primary containment process penetrations bellows cycle basis is a TLAA.

This evaluation was performed as part of the ASME Section III, Class 2 and 3 and ANSI B31.1 fatigue evaluation and is described in Section A.3.3.5.

The containment penetration bellows fatigue design criteria remains valid for the SPEO in accordance with 10 CFR 54.21(c)(1)(i).

A.3.6 Other Plant-Specific TLAA

A.3.6.1 Fatigue of Cranes

A review of design specifications for cranes within the scope of SLR was performed to identify those cranes that comply with Crane Manufacturers Association of America Specification 70 (CMAA-70) and, therefore, have a defined service life as measured in load cycles. The defined service life for these cranes as measured in load cycles is identified as a TLAA for SLR.

The cranes considered to be a TLAA are those in compliance with NUREG-0612 and in the scope of SLR for their lifting function. The Reactor Building and Turbine Building cranes comply with NUREG-0612 and are included in scope of SLR for their lifting function.

These cranes were designed in accordance with Specification 61 of the Electrical Overhead Crane Institute (EOCI Specification 61). Although not originally in accordance with CMAA-70, the original design of the cranes meets CMAA-70 requirements.

The MNGP Reactor Building Crane System design conservatively considers that the following heavy load cycles will be required:

- 20 lifts per year of Reactor Building shield blocks and plugs
- 2 lifts per year of the reactor vessel head
- 2 lifts per year of the drywell vessel head
- 2 lifts per year of the steam separator assembly and
- 2 lifts per year of the steam dryer assembly

In addition to these heavy load cycles, this SLR evaluation also considered the following cycles:

- 500 lifts as a conservative estimate for plant construction
- 4 lifts per year for miscellaneous activities
- 180 lifts for already completed ISFSI Casks (30 @ 6 lifts/cask)
- 4 lifts per year for planned ISFSI Casks (2022-2050, 6 lifts/cask)
- 120 lifts for Low Level Waste Cask Load (6 lifts/cask)

Without consideration for the fact that the modified Reactor Building Crane System was installed after several years of operation the total amount of heavy lifts during an 80 year life is 4,032 cycles. The Reactor Building Crane is conservatively designed to handle 70,000 heavy loads. However, the criteria of 20,000 heavy loads according to CMAA-70 Table 3.3.3.1.3-1 is used as a more conservative limit.

The Turbine Building Crane is used to lift heavy loads like the generator rotors, high-pressure rotors and shells, and low-pressure rotors, hoods, and inner casings. A review of turbine heavy load liftings showed that there were 176 heavy lifts in MNGPs history. Using conservative assumptions, the fatigue analysis determined that the crane is expected to be subjected to less than 3,000 heavy lifts during the 80 year SPEO, which is significantly less than the CMAA-70 limiting value of 20,000 cycles

Therefore, based on the evaluation above, the crane load cycle limits have been projected through the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.3.6.2 Fatigue Analyses of High-Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Turbine Exhaust Penetrations

To evaluate the effects of testing the operability and performance of the turbine-pump units on a periodic basis MNGP conducted a detailed evaluation of the thermal cycles experienced during testing for initial LR. Since the number of cycles used in the evaluation is based on a 60-year plant life this is a TLAA.

For the HPCI turbine exhaust penetration, a higher fatigue usage of 0.111 is conservatively multiplied by (80 years/40 years) to obtain a usage of 0.222 for 80 years of operation. Given this conservatism and the fact that, except for thermal and pressure cycles, none of the stresses increase due to EPU, 0.222 is bounding for 80 years with EPU .

For the RCIC turbine exhaust penetration, the total fatigue usage is conservatively multiplied by (80 years)/(40 years). Given this conservatism and the fact that, except for thermal and pressure cycles, none of the stresses increase due to EPU, 0.686 is bounding for 80 years with EPU.

A.3.6.3 Condensate Backwash Receiving Tank Fatigue Analysis

As part of the MNGP EPU program to increase maximum thermal power to 2,004 megawatts thermal (MWt), the largest impact of the Liquid Waste Management System would be the increase in liquid and wet solid waste resulting from more frequent backwashing of the condensate demineralizers. Backwashed sludge from the condensate demineralizers is collected in the Condensate Backwash Receiving Tank, where it is dewatered and packaged as solid waste for disposal off-site.

Additionally, the internal pressure in the Condensate Backwash Receiving Tank was subsequently increased in support of the EPU. As a result of this pressure increase, a fatigue evaluation was performed to accommodate the increased backwash cycles performed at a greater airburst pressure. This fatigue evaluation projected a conservative value of 160 cycles (i.e., airbursts) per year, which extrapolates to 9,600 cycles over a 60 year operating period (40 years of operation plus 20 years of initial license renewal). Alternating stresses in the system were examined to determine an allowable number of cycles for the tank of 35,000 airbursts under normal and accident conditions. Applying this limit, the usage factor for 60 years of operation was found to be 0.28.

The original calculation assumed 160 cycles per year. Over 80 years of operation, the number of cycles estimated is 12,800. This is conservative as the increased pressure and number of backwash cycles was not implemented until EPU (2008). However, even with this conservatism, fatigue usage for this component is calculated to be 0.37, with significant margin to the limit of 35,000 cycles.

The Condensate Backwash Receiving Tank fatigue evaluation has been projected to the end of the SPEO in accordance with 10 CFR 54.21(c)(1)(ii).

A.4 Subsequent License Renewal (SLR) Commitments List

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
1	Fatigue Monitoring (A.2.1.1)	X.M1	The Fatigue Monitoring AMP is an existing program that will be enhanced to: a) Update plant procedures to require periodic validation of chemistry parameters that are used as inputs to determine F_{en} factors; b) Update plant procedures to identify and require monitoring of the 80-year plant design cycles, or projected cycles that are utilized as inputs to component CUF_{en} calculations, as applicable; c) Update plant procedures to identify the corrective action options to take if the values assumed for fatigue parameters are approached, transient severities exceed the design or assumed severities, transient counts exceed the design or assumed quantities, transient definitions have changed, unanticipated new fatigue loading events are discovered, or the geometries of components are modified; d) Update plant procedures to require trending be performed to ensure that the fatigue parameter limits will not be exceeded during the SPEO; e) Update plant procedures to specify that acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design limit will not be exceeded during the SPEO. For CUF_{en} analyses, scope expansion includes consideration of other locations with the highest expected CUF_{en} values.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
2	Neutron Fluence Monitoring (A.2.1.2)	X.M2	The Neutron Fluence Monitoring AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
3	Environmental Qualification of Electric Equipment (A.2.1.3)	X.E1	The Environmental Qualification of Electric Equipment AMP is an existing program that will be enhanced to: a) Visually inspect accessible, passive EQ equipment at least once every 10 years with the first periodic visual inspection being performed prior to the SPEO. b) Document within the visual inspections that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate age degradation. c) Evaluate and take appropriate corrective actions, which may include changes to qualified life, when an unexpected ALE or condition is identified during operational or maintenance activities that affect the qualification of electrical equipment.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
4	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.2.1)	XI.M1	The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
5	Water Chemistry (A.2.2.2)	XI.M2	The MNGP Water Chemistry AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
6	Reactor Head Closure Stud Bolting (A.2.2.3)	XI.M3	The MNGP Reactor Head Closure Stud Bolting AMP is an existing program that will be enhanced to: a) Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of newly procured material is limited to a measured yield strength less than 150 ksi.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
7	BWR Vessel ID Attachment Welds (A.2.2.4)	XI.M4	The BWR Vessel ID Attachment Welds AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
8	BWR Stress Corrosion Cracking (A.2.2.5)	XI.M7	The BWR Stress Corrosion Cracking AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
9	BWR Penetrations (A.2.2.6)	XI.M8	The BWR Penetrations AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
10	BWR Vessel Internals (A.2.2.7)	XI.M9	The BWR Vessel Internals AMP is an existing program that will be enhanced to: a) Include implementation of BWRVIPs -26-A, -41-R4-A, -47-A, and -183-A as indicated in BWRVIP-315.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
11	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (A.2.2.8)	XI.M12	The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP will be implemented as a new program. The program will provide reasonable assurance that reactor coolant pressure boundary CASS components potentially susceptible to thermal aging embrittlement maintain their intended function(s).	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
12	Flow-Accelerated Corrosion (A.2.2.9)	XI.M17	The Flow-Accelerated Corrosion AMP is an existing program that will be enhanced to: a) Perform a re-assessment of piping systems that have been excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L-R4) to ensure that adequate bases exist to justify this exclusion for the SPEO. b) Provide guidance to evaluate inspection results to determine if assumptions in the extent of condition review remain valid. If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities should consider the number or duration of these occurrences.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
13	Bolting Integrity (A.2.2.10)	XI.M18	The Bolting Integrity AMP is an existing program that will be enhanced to: a) Ensure references to EPRI Reports 1015336 and 1015337 are added and recommendations for bolt replacement as well as the guidance for materials selection and use of lubricants and sealants incorporated, as appropriate. b) All lubricants containing sulfur will be prohibited from use on pressure-retaining closure bolting. c) Ensure that the maximum yield strength of newly procured pressure-retaining bolting material will be limited to an actual yield strength less than 150 ksi. d) Ensure that closure bolting where leakage is difficult to detect (e.g., on pressure-retaining components in piping systems that are submerged or that contain air or gas) is inspected for cracking and/or loss of material as applicable for the material and environment combination. In addition, the inspections will confirm that the bolted connections are leak tight by applying alternative inspection techniques such as soap bubble testing, thermography, acoustic testing, or verifying the closure bolting is hand tight. A representative sample of the population (defined as the same material and environment combination) of bolt heads and threads will be inspected over each 10-year period of the SPEO. The representative sample will be 20 percent of the population (up to a maximum of 25 items). Opportunistic inspections during maintenance activities may be credited during the same 10-year period. e) Ensure that bolted joints not readily visible during plant operations and refueling outages will be inspected when they are made	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			accessible and at such intervals that would provide reasonable assurance the components' intended functions are maintained. f) Ensure that closure bolting greater than 2 in. in diameter with actual yield strength greater than or equal to 150 ksi or yield strength is unknown will require volumetric examination in accordance to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1. g) Project, where practical, identified degradation until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. Adverse results will be evaluated to determine if an increased sample size or inspection frequency is required. h) Include the guidance for corrective action as described in NUREG-2191, Chapter XI.M18, Element 7.	
14	Open-Cycle Cooling Water System (A.2.2.11)	XI.M20	The Open-Cycle Cooling Water System AMP is an existing program that will be enhanced to: a) Update procedures to monitor for internal cracking.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Ensure Non-ASME Code tests and inspections follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. c) Clarify that inspection results are trended to evaluate the adequacy of surveillance frequencies so that proper intended function is maintained between surveillances. d) Clarify that if fouling is identified, the overall effect is evaluated for reduction of heat transfer capability (if applicable), flow blockage, loss of material, and chemical treatment effectiveness. e) Include trending of wall thickness measurements at locations susceptible to ongoing degradation and adjustment of the monitoring frequency and number of inspection locations based on the trending. f) Clarify that 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 relevant primary program procedure will also be updated to state that the number of inspections will be increased in accordance with the CAP; however, no fewer than 5 additional inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
15	Closed Treated Water Systems (A.2.2.12)	XI.M21A	The Closed Treated Water Systems AMP is an existing program that will be enhanced to: a) Include the Heating and Ventilation (HTV) Cooling System as a closed treated water system. b) Ensure visual inspections evaluate the visual appearance of surfaces for evidence of loss of material. Include acceptance criteria for the results of visual inspection of surfaces exposed to the closed treated water environment. Any detectable loss of material, cracking, or fouling (of heat transfer surfaces) will be evaluated in the CAP. Perform visual inspections to determine surface cleanliness, or functional testing to verify that design heat removal rates are maintained as applicable. c) Ensure surface or volumetric examinations results are evaluated for surface discontinuities indicative of cracking. d) Visually inspect surfaces exposed to the closed treated water environment for evidence of loss of material, cracking, or fouling (of heat transfer surfaces) whenever the system boundary is opened. At a minimum, in each 10-year period during the SPEO, a representative sample (20 percent of the population, up to a maximum of 25 components) of piping and components will be inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The 20 percent minimum is surface area inspected unless the component is measured in linear feet, such as piping. In that case, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. The representative sample will be selected based on likelihood of corrosion or cracking. Inspections will be conducted in accordance with applicable ASME code requirements. If there are no ASME code requirements, inspections will be conducted in accordance with site	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			procedures, which will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. e) Include corrective actions if the results of visual inspection of surfaces exposed to the closed treated water environment do not meet acceptance criteria. If fouling of heat transfer surfaces is identified, the overall effect will be evaluated for reduction of heat transfer, flow blockage, and loss of material. If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement 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 will be determined in accordance with the CAP; however, there will be no fewer than 5 additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging affect 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 condition. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.	
16	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (A.2.2.13)	XI.M23	The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is an existing program that will be enhanced to: a) Update program procedures to state their respective visual inspection frequencies required by ASME B30.2 or other appropriate standards of the ASME B30 series.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Update program procedures to replace obsolete references to NP-5067 and EPRI TR-104213 with reference to EPRI Reports 1015336 and 1015337. c) Update program procedures to state load handling system visual inspections are performed by personnel qualified in accordance with plant-specific procedures and processes. d) Update program procedures to inspect the Reactor Building crane trolley and bridge runway rail web and flange for damage or cracks. e) Update program procedures to generate a corrective action to evaluate any non-conforming conditions. f) Update program procedures to state that any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload is evaluated according to ASME B30.2 or other applicable industry standard in the ASME B30 series. g) Update program procedures to state that repairs made to NUREG-0612 load handling systems are performed as specified in ASME B30.2 or other applicable industry standard in the ASME B30 series.	
17	Compressed Air Monitoring (A.2.2.14)	XI.M24	The Compressed Air Monitoring AMP is an existing program that will be enhanced to: a) Incorporate the air quality provisions provided in the guidance of EPRI TR-108147 and the related guidance in ASME OM-2012, Division 2, Part 28.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Perform opportunistic visual inspections of accessible internal surfaces for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system. Acceptance criteria for visual inspection of internal surfaces will include no signs of corrosion (general, pitting, and crevice) that could indicate that the potential loss of function of the component, and the inspections and tests will be performed by qualified personnel. c) Trend the routine dew point temperature measurements. d) Include monitoring and trending guidance from ASME OM-2012, Division 2, Part 28 as applicable. e) Update procedures to take appropriate corrective actions when corrosion is discovered on internal system surfaces.	
18	Fire Protection (A.2.2.15)	XI.M26	The Fire Protection AMP is an existing program that will be enhanced to: a) Update the fire damper assemblies inspection procedure(s) to inspect for corrosion and cracking on all in-scope fire damper assemblies. Include “no signs of corrosion, cracking or degradation that could result in loss of fire protection capability due to loss of material” as acceptance criteria for fire damper assemblies. b) Trend the inspection results on fire barrier penetration seals, fire barriers, fire damper assemblies, and fire doors for timely detection of aging effect so that appropriate corrective actions can be taken. Where practical, identified degradation is projected until the next scheduled inspection c) Specify that for sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g.,	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. d) Require an assessment for additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. e) Update Fire Protection AMP documents to include "no separation of layers of material" and "no ruptures or punctures" as acceptance criteria for fire barrier penetration seals. f) Indicate that, for fire barrier penetration seals, if degradation that could result in loss of fire protection capability is detected within the inspection sample of penetration seals, that the scope of the inspection is expanded to include additional seals in accordance with the MNGPs Fire Protection AMP. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's CAP.	
19	Fire Water System (A.2.2.16)	XI.M27	The Fire Water System AMP is an existing program that will be enhanced to: a) Clarify that when visual inspections are used to detect loss of material, the inspection technique must be capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations are performed. b) Perform volumetric wall thickness inspections on the portions of the water-based fire protection system components that are periodically subjected to flow but are normally dry as follows: In each 5-year	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement the AMP and start the pre-SPEO inspections and tests no earlier than 5 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			interval of the SPEO, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping. If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary. c) Incorporate the surveillance requirements stated in NUREG-2191, Section XI.M27, Element 4 and Table XI.M27-1, which are based on NFPA 25, 2011 edition, with an exception to main drain testing as stated in A.2.2.16. This includes testing or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, in accordance with NFPA 25. d) Clarify that, where practical, degradation identified will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. Results of flow testing (e.g., buried and underground piping, fire mains, and sprinklers/spray nozzles), flushes, and wall thickness measurements will be monitored and trended per the instructions of the specific test/inspection procedure. Degradation identified by flow testing, flushes, and inspections will be evaluated. If the condition of the piping/component does not meet acceptance criteria, then the issue will be entered into the corrective action program, and the component will be evaluated for cleaning, recoating, repair, or replacement. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components'	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			intended functions throughout the SPEO based on the projected rate and extent of degradation. e) Update spray and sprinkler system flushing procedures to document and trend deposits (scale or foreign material). Incorporate acceptance criteria that no loose fouling products can exist in the systems that could cause flow blockage in the sprinklers or deluge nozzles. Include steps in flushing procedures to compare the amount of deposits to the previous inspections' results, and if the trend shows increasing deposits, then the CAP will be utilized to drive improvement. f) Clarify that identified wall loss greater than the manufacturer's tolerance will be entered into the CAP for engineering evaluation and trending to determine when minimum wall thickness will be reached and what corrective actions are required. g) Update pipe inspection procedures to state that if an obstruction inside piping or sprinklers is detected during pipe inspections, the material is removed, and the inspection results are entered into the CAP for further evaluation. An evaluation is conducted to determine if deposits need to be removed to determine if loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers is detected, a flush is conducted in accordance with the guidance in NFPA 25 Annex D.5, "Flushing Procedures." If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the CAP. h) Update procedures to state that if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation, then additional tests will be conducted. The number of increased tests is determined in accordance with the CAP; however, there are no	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis will be conducted to determine the further extent of tests. i) Clarify that for ongoing degradation mechanisms such as MIC or recurring internal corrosion, the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation. The number of increased inspections is determined in accordance with the CAP; however, no fewer than 5 additional inspections are conducted for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination is inspected, whichever is less. The additional inspections will occur at least every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for “loss of material due to recurring internal corrosion” as defined in NUREG 2192. 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 reinspection interval. If a failure occurs (e.g., a through-wall leak or blockage impacting operability), the failure mechanism shall be identified and used to determine the most susceptible system locations for additional inspections, including consideration to the other unit systems as driven by the corrective action program. When piping is replaced prior to failure, due to concerns with wall thinning or blockage, inspections are considered for	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			similar areas of the system to determine the presence and extent of degradation.	
20	Outdoor and Large Atmospheric Metallic Storage Tanks (A.2.2.17)	XI.M29	The Outdoor and Large Atmospheric Metallic Storage Tanks AMP will be implemented as a new program. The program will manage the aging effects on the external and internal surfaces of in-scope outdoor metallic aboveground tanks constructed on concrete.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement and start the 10-year interval of the volumetric inspections of the CST tank bottoms, and the visual inspections of the tank internals exposed to air and condensation environment no earlier than 10 years prior to the SPEO.
21	Fuel Oil Chemistry (A.2.2.18)	XI.M30	The MNGP Fuel Oil Chemistry AMP is an existing program that will be enhanced to: a) Periodically check for and remove water accumulation in the Diesel Fire Pump Day Tank. b) Include sampling of the day tanks and base tanks, in addition to the samples taken from the Diesel Oil Storage Tank, subject to the same standards. Ensure that the sampling of all diesel oil storage tanks specifically monitors the following parameters for trending purposes: water content, sediment content, biological activity, and total particulate concentration.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Start the 10-year interval inspections no earlier than 10 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Include the following monitoring and trending features for visual and volumetric inspection methodology: ○ Project identified degradation until the next scheduled inspection, where practical. ○ Evaluate results against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. d) Include the following acceptance criteria for visual and volumetric inspection procedures: ○ Corrective actions are taken if microbiological activity is detected. ○ Report and evaluate any degradation of tank internal surfaces using the CAP. ○ Evaluate thickness measurements of the diesel oil storage tank bottoms against the design thickness and corrosion allowance. e) Include the addition of biocide to the fuel oil when the presence of biological activity is confirmed, or if there is evidence of MIC.	
22	Reactor Vessel Material Surveillance (A.2.2.19)	XI.M31	The Reactor Vessel Material Surveillance AMP is an existing program that will be enhanced to: a) Implement BWRVIP-321-A and subsequent NRC approved revisions upon obtaining NRC approval for MNGP to use BWRVIP-321-A to maintain compliance with 10 CFR Part 50, Appendix H.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
23	One-Time inspection (A.2.2.20)	XI.M32	The One-Time Inspection AMP will be implemented as a new program. The program will verify: • The system-wide effectiveness of AMPs that are designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO, • The insignificance of an aging effect, and • 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.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement the AMP and start the one-time inspections no earlier than 10 years prior to the SPEO.
24	Selective Leaching (A.2.2.21)	XI.M33	The Selective Leaching AMP is an existing program that will be enhanced to: a) Include inspection of susceptible components exposed to treated water, Closed-Cycle Cooling Water, and waste water, or buried in soil. b) Perform one-time inspections of a representative sample of each population (material/environment combination) for components exposed to closed-cycle cooling water or treated water. In the 10-year period prior to the SPEO, a sample of 3 percent of the population or a maximum of 10 components per population will be visually and mechanically (for gray cast iron and ductile iron components) inspected. Inspections, where possible, will focus on the bounding or lead components most susceptible to aging based on time-in-service and severity of operating conditions for each population. c) Perform periodic inspections for components exposed to raw water, waste water, or soil. For raw water and waste water environments, the	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Perform the one-time inspections no earlier than 10 years prior to the SPEO and no later than 6 months prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			populations may be combined as long as an evaluation is conducted to determine the more severe environment and the inspections and examinations are conducted on components in the most severe environment, with one inspection being conducted in the less severe environment. Periodic inspections will be conducted in the 10-year period prior to the SPEO and in each 10-year period during the SPEO. In these periodic inspections, a sample of 3 percent of the population or a maximum of 10 components per population will be visually and mechanically (for gray cast iron and ductile iron components) inspected. When inspections are performed on piping, a 1-foot axial length section will be considered as one inspection. In addition, for sample populations with greater than 35 susceptible components, two destructive examinations will be performed in each material and environment population in each 10-year period. When there are less than 35 susceptible components in a sample population, one destructive examination will be performed for that population. Otherwise, a technical justification of the methodology and sample size used for selecting components for inspection will be included as part of the program's documentation. The number of visual and mechanical inspections may be reduced by two for each component that is destructively examined beyond the minimum number of destructive examinations recommended in each 10-year interval. Inspections, where possible, will focus on the bounding or lead components most susceptible to aging based on time-in-service and severity of operating conditions for each population. Opportunistic inspections may be credited as periodic inspections as long as the inspection locations selection criteria are met. d) Include guidance on inspection parameters such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. e) Include the following guidance regarding Monitoring and Trending:	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			○ Where practical, identified degradation is projected until the next scheduled inspection. ○ Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. f) Include the following acceptance criteria: ○ For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide; ○ For gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations; ○ The presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal while not taking credit for the material properties of the dealloyed portion of the component as part of the determination; and ○ The components meet system design requirements such as minimum wall thickness, when extended to the end of the SPEO. g) Include the following guidance regarding Corrective Actions: ○ 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 SPEO, additional inspections are performed if the cause of the aging effect for each applicable material and	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			environment is not corrected by repair or replacement for 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 5 additional visual and mechanical inspections when visual and mechanical inspections(s) did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria. 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. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. h) Require the removal of interferences to access or remove components most susceptible to selective leaching having difficult-to-access surfaces (e.g., heat exchanger shell interiors, exterior of heat exchanger tubes) if unacceptable inspection findings occur within the same material and environment population.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
25	ASME Code Class 1 Small-Bore Piping (A.2.2.22)	XI.M35	The ASME Code Class 1 Small-Bore Piping AMP will be implemented as a new program. The program will manage the effects of SCC and cracking due to thermal or vibratory fatigue loading for certain ASME Code Class 1 small-bore piping through volumetric or destructive testing.	Complete all inspections no later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement AMP and complete inspections within 6 years prior to the SPEO.
26	External Surfaces Monitoring of Mechanical Components (A.2.2.23)	XI.M36	The External Surfaces Monitoring of Mechanical Components AMP is an existing program that will be enhanced to: a) Revise procedures to inspect heat exchanger surfaces exposed to air for evidence of reduction of heat transfer due to fouling. b) Revise procedures to ensure areas that are frequently wetted are inspected. c) Specify in procedures that situations where the similarity of the internal and external environments are such that the external surface condition is representative of the internal surface condition, external inspections of components may be credited for managing: • loss of material and cracking of internal surfaces for metallic components, • loss of material and cracking of internal surfaces for polymeric components, and	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• hardening or loss of strength of internal surfaces for elastomeric components. • When credited, the program provides the basis to establish that the external and internal surface condition and environment are sufficiently similar. d) Revise procedures to add the following inspection parameters for metallic components: • Corrosion stains on thermal insulation • Blistering of protective coatings • Accumulation of debris on heat exchanger tube surfaces and air-side heat exchanger surfaces. e) Revise procedures to include inspection for elastomeric and polymeric components and its methodology. The sample size for manipulation is at least 10 percent of available surface area. The inspection parameters for elastomers and polymers shall include the following: • Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”) • Loss of thickness • Exposure of internal reinforcement for reinforced elastomers • Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			f) Revise procedures to specify that inspections are to be performed by personnel qualified in accordance with site procedures and programs to perform the specified task, and when required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). g) Revise procedures to ensure non-ASME Code inspections and tests include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings. Surfaces that are not readily visible during plant operations and refueling outages should be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. h) Revise procedures to specify that, when inspecting to manage cracking of a component's material, either surface examinations conducted in accordance with plant-specific procedures or ASME Code Section XI VT-1 inspections (including those inspections conducted on non-ASME Code components) are conducted on each component inspected. An inspection requires that at least 20 percent of the surface area of the component is inspected, unless the component is measured in linear feet, such as piping. Any combination of 1-foot length sections and components can be used to meet the recommended extent of 20 percent of the population of materials and environment combinations, with a maximum of 25 inspections required in each population. 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. i) Revise procedures to specify alternative methods for detecting moisture inside piping insulation to be used for inspecting piping	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			jacketing that is not installed in accordance with plant-specific procedures. j) Revise procedures to include the following information: • Component surfaces that are insulated and exposed to condensation, and insulated outdoor components, are periodically inspected every 10 years during the SPEO. • For all outdoor components and any indoor components exposed to condensation (because the in-scope component is operated below the dew point), inspections are conducted of each material type (e.g., steel, stainless steel, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. k) Revise procedures to specify that:	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			• Visual inspection will identify direct indicators of loss of material due to wear to include dimension change, scuffing, and, for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. • Visual inspection of elastomers and flexible polymers will identify indirect indicators of elastomer and flexible polymer hardening or loss of strength, including the presence of surface cracking, crazing, discoloration, and, for elastomers with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. • Visual inspections will cover 100 percent of accessible component surfaces. • Manual or physical manipulation can be used to augment visual inspection to confirm the absence of hardening or loss of strength for elastomers and flexible polymeric materials where appropriate, and the sample size for manipulation is at least 10 percent of available surface area. l) Revise procedures to formalize sampling-based inspections. The results of sampling-based inspections will be evaluated against acceptance criteria to confirm that the sampling bases will maintain intended functions of the components throughout the SPEO based on the projected rate and extent of degradation. m) Revise procedures to add an evaluation to project the degree of observed degradation to the end of the SPEO or the next scheduled inspection, whichever is shorter.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			n) Revise procedures to specify, where practical, acceptance criteria are quantitative. o) Revise procedures to specify that if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the CAP.	
27	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (A.2.2.24)	XI.M38	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be implemented as a new program. The program will manage loss of material, cracking, blistering, wall thinning, reduction of heat transfer, hardening or loss of strength of elastomeric and polymeric components, and flow blockage via inspections performed during periodic system and component surveillances.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement the AMP and perform pre-PEO baseline inspections no earlier than 10 years prior to the SPEO
28	Lubricating Oil Analysis (A.2.2.25)	XI.M39	The Lubricating Oil Analysis AMP is an existing program that will be enhanced to: a) Clarify that phase-separated water in any amount is not acceptable. If phase-separated water is identified in the sample, then corrective actions are to be initiated to identify the source and correct the issue.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
29	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (A.2.2.26)	XI.M40	The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
30	Buried and Underground Piping and Tanks (A.2.2.27)	XI.M41	The Buried and Underground Piping and Tanks AMP is an existing program that will be enhanced to: a) Ensure that new or replaced backfill shall meet the requirements of NACE SP0169-2007 Section 5.2.3 or NACE RP0285-2002 Section 3.6. b) Measure wall thickness with volumetric examination or pit depth gages or calipers using techniques that have been determined to be effective for the material, environment, and conditions (e.g., remote methods) during the examination and are capable of quantifying general wall thickness and the depth of pits. c) Perform visual inspection of the external surfaces of controlled low strength material backfill, where such backfill is used, to detect potential cracks that could admit groundwater to the surface of the component. d) Inspect for cracking due to stress corrosion cracking in stainless steel and steel (in a carbonate-bicarbonate environment) utilizing a method that has been determined to be capable of detecting cracking. Coatings that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate do not have to be removed. Inspections for cracking are conducted to assess the impact of cracks on the pressure boundary function of the component. e) Perform inspections of buried and underground piping and tanks in accordance with NUREG-2191 Table XI.M41-2 Preventive Action Category F for buried steel, unless a reevaluation of cathodic protection system performance, future OE, or soil conditions determines that another Preventive Action Category is more	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement the AMP and start 10-year interval inspections no earlier than 10 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			applicable. In the 10-year period prior to and during SPEO for each 10-year interval, perform buried and underground piping and tanks inspections in accordance with the Preventive Action Category F as outlined in NUREG-2191 Table XI.M41-2. When the inspections for a given material type is based on percentage of length and results in an inspection quantity of less than 10 feet, then 10 feet of piping is inspected. If the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping is inspected. f) Perform surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed. g) Include the guidance for piping inspection location selection as follows: (a) a risk ranking system software incorporates inputs that include coating type, coating condition, cathodic protection efficacy, backfill characteristics, soil resistivity, pipe contents, and pipe function; (b) opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met; and (c) the use of guided wave ultrasonic examinations may not be substituted for the required inspections. h) Degradation (e.g., coating condition, wall thinning) is projected, where practical, until the next scheduled inspection. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. i) Utilize an acceptance criterion of no evidence of coating degradation. Otherwise have the type and extent of coating degradation evaluated as insignificant by an individual: (a) possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (b) who has	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			completed the Electric Power Research Institute Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (c) a coatings specialist qualified in accordance with an ASTM standard endorsed in RG 1.54, Revision 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." j) Clarify that indications of cracking in metallic pipe are managed in accordance with the CAP. k) Clarify that backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the component's coatings or the surface of the component (if not coated). l) Clarify that for pressure tests, the test acceptance criteria are that there are no visible indications of leakage, and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or by quantified leakage across test boundary valves. m) Clarify that cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable. n) Require an extent of condition evaluation to determine the extent of degraded backfill in the vicinity where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill. o) Evaluate the coated and uncoated metallic piping and tanks that show evidence of corrosion to ensure that the minimum wall thickness is maintained throughout the SPEO. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the SPEO meets minimum wall thickness requirements, the NUREG-2191	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			Section XI.M41 recommendations for expansion of sample size do not apply. p) Repair the degraded condition or replace the affected component when the coatings, backfill, or the condition of exposed piping does not meet the acceptance criteria. Expand the sample size when the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the SPEO in the following manner: The number of inspections within the affected piping categories are doubled or increased by 5, whichever is smaller. If the acceptance criteria are not met in any of the expanded samples, an analysis is conducted to determine the extent of condition and extent of cause. The number of follow-on inspections is determined based on the extent of condition and extent of cause. The timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection is completed within the 10-year interval in which the original inspection was conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval. These additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited towards the number of required inspections for the following 10-year interval. The number of inspections may be limited by the extent of piping or tanks subject to the observed degradation mechanism.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
31	Internal Coatings/Linings For In-scope Piping, Piping Components, Heat Exchangers, and Tanks (A.2.2.28)	XI.M42	The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new program. The program will manage the degradation of internal coatings/linings exposed to raw water, treated water, or waste water that can lead to loss of material of base metals or downstream effects such as reduction in flow, pressure, or heat transfer when coatings/linings become debris.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement the AMP and perform pre-PEO baseline inspections no earlier than 10 years prior to the SPEO.
32	ASME Section XI, Subsection IWE (A.2.2.29)	XI.S1	The ASME Section XI, Subsection IWE AMP is an existing program that will be enhanced to: a) Revise procedures to specify the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using High-Strength Bolts,” for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts. b) Revise procedures to specify that accessible noncoated surfaces (including those comprising the torus vent system) are monitored for arc strikes.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO. Start the one-time inspections in commitments 32-c), 32-d) no earlier than 5 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			c) Implement periodic supplemental surface or enhanced visual examinations, in addition to visual examinations, at intervals no greater than 10 years to detect cracking on accessible portions of high-temperature drywell piping penetrations that are not pressurized during local leak rate testing and have no CLB fatigue analysis. Cracking is corrected by repair or replacement or accepted by engineering evaluation. d) Conduct supplemental one-time surface or enhanced visual examinations, performed by qualified personnel using methods capable of detecting cracking, comprising a representative sample 5 of the stainless steel penetrations or dissimilar metal welds associated with high-temperature (temperatures above 140°F) stainless steel piping systems in frequent use. These inspections are intended to confirm the absence of SCC aging effects. e) Revise procedures to specify a one-time volumetric examination of metal shell surfaces that are inaccessible from one side if triggered by plant-specific OE identified after the date of issuance of the initial renewed license. If triggered, this inspection will be performed by sampling randomly selected, as well as focused, metal shell locations susceptible to corrosion that are inaccessible from one side. The trigger for this one-time examination is plant-specific occurrence or recurrence of metal shell corrosion (base metal material loss exceeding 10% of nominal plate thickness) that is determined to originate from the inaccessible side. Any such instance would be identified through code inspections performed since November 8, 2006. Guidance provided in EPRI TR–107514 will be considered when establishing a sampling plan. This sampling is conducted to demonstrate, with 95% confidence, that 95% of the accessible portion of the metal shell is not experiencing greater than 10% wall loss.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			f) If SCC is identified as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site's corrective action process. This will include one additional penetration with dissimilar metal welds associated with greater than 140°F stainless steel piping systems until cracking is no longer detected. Periodic inspection of subject penetrations with dissimilar metal welds for cracking will be added to the ASME Section XI, Subsection IWE AMP if necessary, depending on the inspection results.	
33	ASME Section XI, Subsection IWF (A.2.2.30)	XI.S3	The ASME Section XI, Subsection IWF AMP is an existing program that will be enhanced to: a) Revise procedures to evaluate the acceptability of inaccessible areas (e.g., portions of ASME Class 1, 2, and 3 supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions are identified in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. b) Revise procedures to clarify that in addition to molybdenum disulfide (MoS_2), other lubricants containing sulfur will be prohibited from use on structural bolting. c) Revise procedures to specify the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of Research Council for Structural Connections publication "Specification for Structural Joints Using High-Strength Bolts," for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO. Start the one-time inspection in commitment 33-g) no earlier than 5 years prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			d) Revise procedures to specify that elastomeric or polymeric vibration isolation elements are monitored for cracking, loss of material, and hardening. e) Revise procedures to specify that accessible sliding surfaces are monitored for significant loss of material due to wear and accumulation of debris or dirt. f) Perform and document a one-time inspection of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. g) Revise procedures to include tactile inspection (feeling, prodding) of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect. h) Revise procedures to specify that, for component supports with high-strength bolting greater than one-in. nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. A representative sample of bolts will be inspected during the inspection interval prior to the start of the SPEO and in each 10-year period during the SPEO. Identify the population of ASME Class 1, 2, and 3 high-strength structural bolting greater than one-in. nominal diameter within the boundaries of IWF-1300 and establish a sample to be 20% of the population (for a material/environment combination) up to a maximum of 25 bolts.	

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			i) Revise procedures to increase or modify the component support inspection population when a component support is repaired to as-new condition by including another support that is representative of the remaining population of supports that were not repaired. j) Revise procedures to specify that the following conditions are also unacceptable: • Loss of material due to corrosion or wear; • Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support; • Cracked or sheared bolts, including high-strength bolts, and anchors; • Loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function; and • Cracks.	
34	10 CFR Part 50, Appendix J (A.2.2.31)	XI.S4	The 10 CFR Part 50, Appendix J AMP is an existing program that is credited.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO.

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
35	Masonry Walls (A.2.2.32)	XI.S5	The Masonry Walls Amp is an existing program that will be enhanced to: a) Update the implementing procedure to include the inspection of masonry walls in the EFB and Radwaste Building. b) Update the implementing procedure to monitor and inspect for gaps between the supports and masonry walls that could potentially impact the intended function or potentially invalidate its evaluation basis. c) Update the implementing procedure for more frequent inspections in areas where significant loss of material, cracking, or other signs of degradation are projected or observed to provide reasonable assurance than there is no loss of intended function between inspections. d) Update the implementing procedure for trending of crack widths and lengths and gaps between supports and masonry walls that approach or exceed acceptance criteria. e) Update the implementing procedure will include projected degradation until the next scheduled inspection where it is practical. f) Update the implementing procedure to include acceptance criteria to ensure observed aging effects do not invalidate the evaluation basis of the wall or impact its intended function. g) Update the implementing procedure to state that if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the MNGP CAP.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
36	Structures Monitoring (A.2.2.33)	XI.S6	The Structures Monitoring AMP is an existing program that will be enhanced to: a) Revise the implementing procedure to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” will be used. b) Revise the implementing procedure to include monitoring and trending of leakage volumes and chemistry for signs of concrete or steel reinforcement degradation if active through-wall leakage or groundwater infiltration is identified. c) Revise the implementing procedure to include provisions for more frequent inspections in areas where significant signs of degradation are projected or observed to provide reasonable assurance than there is no loss of intended function between inspections. d) Revise the implementing procedure to include evidence of water in-leakage as a finding requiring further evaluation. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessment may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water. e) Revise the implementing procedure to include tactile inspection in addition to visual inspection of elastomeric elements to detect hardening.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			f) Revise the implementing procedure to include qualification requirements for both inspection and evaluation personnel that are in accordance with ACI 349.3R-02. g) Revise the implementing procedure to explicitly include inspection of the following components and commodities: • Expansion plugs • Fuel Storage Racks (New Fuel) • Manhole covers, supports • Supports • Concrete Diesel Fuel Oil Storage Tank Deadmen • Vibration Isolation Elements • Electrical Enclosures • RPV to Drywell Refueling Seal • Exterior Surfaces of Roofing h) Revise the implementing procedure to include acceptance criteria for concrete surfaces based on the “second-tier” evaluation criteria provided in ACI 349.3R-02. i) Revise the implementing procedure to include that if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the CAP.	
37	Inspection of Water-Control Structures Associated with Nuclear Power Plants (A.2.2.34)	XI.S7	The Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing program that will be enhanced to: a) Revise the implementing procedure to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

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No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used. b) State that further evaluation of evidence of groundwater infiltration or through-concrete leakage may also include destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels, and that assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the leakage water if leakage volumes allow. c) Ensure that the implementing procedure states that visual inspections of inaccessible concrete for evidence of leaching of calcium hydroxide and carbonation are performed. d) Include qualification requirements for both inspection and evaluation personnel that is in accordance with ACI 349.3R. e) Include trending of quantitative measurements and qualitative information for findings exceeding the acceptance criteria for all applicable parameters monitored or trended.	
38	Protective Coating Monitoring and Maintenance (A.2.2.35)	XI.S8	The Protective Coating Monitoring and Maintenance AMP is an existing program that will be enhanced to: a) Specify that thorough visual inspections shall be carried out on previously designated areas and on areas noted as deficient during the walk-through. When follow-up inspections beyond visual	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO.

Table A-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			inspections are specified by the Nuclear Coatings Specialist, they will be performed by individuals trained and certified in the applicable reference standards of ASTM Guide D5498 for the inspection designated by the Nuclear Coatings Specialist. b) Specify that any required coatings repairs be prioritized between the current or future outages. c) Specify that if coating areas cannot be inspected, it will be noted in the inspection documentation with a reason why the inspection could not be conducted. d) Reference Position C4 of RG 1.54 Revision 3 for Maintenance of Service Level I Coatings.	
39	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (A.2.2.36)	XI.E1	The Electrical Insulation For Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing program that will be enhanced to: a) Identify the most limiting temperature, radiation, and moisture environments and their basis. Cable and connection inspections are performed for the most limiting insulation plant environments. b) Review plant-specific OE: • For previously identified and mitigated ALEs for cumulative aging effects that could potentially impact service life. • To identify in-scope cable and connection insulation previously subjected to ALE during the original period of extended operation. Cable and connection insulation is evaluated to confirm that the	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

Table A-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			dispositioned corrective actions continue to support in-scope cable and connection intended functions during the SPEO. c) Perform an engineering evaluation when unacceptable visual indications of cable jacket and connection insulation surface anomalies that could potentially lead to a loss of intended function are identified to determine if additional actions are required. Ensure insulation material test results are within the acceptance criteria. d) Test a representative sample of 20 percent of each cable and connection type with a maximum sample size of 25 when a large number of cables and connections are identified as potentially degraded and document the technical basis for the sample selection.	
40	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits (A.2.2.37)	XI.E2	The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits AMP is an existing program that will be enhanced to: a) Revise the implementing procedures to include documented periodic review of calibration test results for neutron monitors and radiation monitors within the scope of this program at least once every 10 years.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Reviews and tests to start prior to SPEO.

Table A-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
41	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (A.2.2.38)	XI.E3A	The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP is an existing program that will be enhanced to: a) Include non-EQ, in-scope, inaccessible medium-voltage power cables that are energized less than 25% of the time and exposed to significant moisture to the scope of this program. b) Inspect in-scope manholes at least once annually and after event-driven occurrences, unless level monitoring system is installed, then manhole inspections will be performed at least once every 5 years and only after event-driven occurrences when indicated by level monitoring system. c) Ensure manhole inspection include direct indication that the cables are not wetted or submerged, and that cable/splices and cable support structures are intact. d) Test medium-voltage power cables within the scope of this program at least once every 6 years.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

Table A-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
42	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (A.2.2.39)	XI.E3B	The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be implemented as a new program. The program will manage the effects of reduced insulation resistance of non-EQ, in-scope, inaccessible instrument and control cables, exposed to significant moisture.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
43	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (A.2.2.40)	XI.E3C	The Electrical Insulation for Inaccessible Low-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be implemented as a new program. The program will manage the effects of reduced insulation resistance of non-EQ, in-scope, inaccessible low-voltage cables, exposed to significant moisture.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO
44	Metal-Enclosed Bus (A.2.2.41)	XI.E4	The Metal-Enclosed Bus AMP is an existing program that will be enhanced to: a) Inspect accessible elastomer and bolted connections that are not covered with heat shrink tape, sleeving, insulating boots, etc. for degradation.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO

Table A-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
			b) Perform an engineering evaluation of MEB segments that are not accessible for inspection. The evaluation can be based on results of accessible MEB inspections, tests, or other analysis. c) Define a representative sample size as 20 percent of the accessible bolted connection population, with a maximum of 25.	
45	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (A.2.2.42)	XI.E6	The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing program that will be enhanced to: a) Perform a one-time test of a representative sample of in-scope connections. Evaluation of the one-time test results will technically justify if periodic testing is warranted at least once every 10 years and will be documented. b) Define a representative sample size as 20 percent of the accessible connector type population, with a maximum sample of 25 per connection type. c) Define that the inspection frequency will be at least once every 5 years only when visual inspections are utilized as an alternative to measurement testing. d) Define the acceptance criteria for thermography, contact resistance measurements, and visual inspections.	No later than 6 months prior to the SPEO, or no later than the last refueling outage prior to the SPEO Implement the AMP and start the one-time and 10-year interval inspections no earlier than 10 years prior to the SPEO.
46	Quality Assurance Program (A.1.3)	Appendix A	The Quality Assurance Program is an existing program that is credited.	Ongoing

Table A-3
List of SLR Commitments and Implementation Schedule

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
47	Operating Experience Program (A.1.4)	Appendix B	The Operating Experience Program is an existing program that is credited.	Ongoing

APPENDIX B

AGING MANAGEMENT PROGRAMS

MONTICELLO NUCLEAR GENERATING PLANT

SUBSEQUENT LICENSE RENEWAL APPLICATION

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B.1 Introduction

B.1.1 Overview

The SLR AMP descriptions are provided in this appendix for each program credited for managing aging effects based upon the AMR results provided in Section 3.1 through Section 3.6 of this SLRA.

In general, there are four types of AMPs:

- Prevention programs that preclude aging effects from occurring;
- Mitigation programs that slow the effects of aging;
- Condition monitoring AMPs that inspect/examine for the presence and extent of aging; and
- Performance monitoring programs that test the ability of a structure or component to perform its intended function.

More than one type of AMP may be implemented for SSCs to ensure that aging effects are managed.

Part of the demonstration that the effects of aging are adequately managed is to evaluate credited programs and activities against certain required attributes. Each of the AMPs described in this section has 10 elements that are consistent with the attributes described in Table 2, "Aging Management Programs Element Descriptions," of NUREG-2191, *Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report*.

Credit has been taken for existing MNGP plant programs whenever possible. However, some existing MNGP programs aligned with multiple NUREG-2191 AMPs, and some NUREG-2191 AMPs aligned with multiple MNGP programs, therefore the existing MNGP AMPs to be continued for SLR will be renamed as applicable to align with the NUREG-2191 AMP names. New MNGP AMPs align with the NUREG-2191 AMP names. All existing MNGP programs and activities associated with in-scope SLR SSCs were considered to determine whether they include the necessary actions to manage the effects of aging.

Certain current MNGP license renewal programs are based on NUREG-1801 (GALL), Revision 0 and include the required SLR 10-element attributes. These current programs have been demonstrated to adequately manage the identified aging effects during the original PEO. If an existing program does not adequately manage an identified aging effect, the finding is entered into the CAP and the program is enhanced, as necessary. The existing AMPs, as well as the new AMPs, are listed in Table B-1 and Table B-2.

Consistent with the discussion above, the following new programs will be created at MNGP for the purposes of SLR:

- MNGP Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.3.8)
- MNGP Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
- MNGP One-Time Inspection AMP (B.2.3.20)
- MNGP ASME Code Class 1 Small-Bore Piping (B.2.3.22)
- MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP (B.2.3.24)
- MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (B.2.3.28)
- MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (B.2.3.39)
- MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP (B.2.3.40)

These new AMPs will be consistent with the 10 elements of their respective NUREG-2191 AMPs.

The following programs each have exception(s) justified with a technical basis:

- MNGP Water Chemistry AMP (B.2.3.2)
- MNGP Reactor Head Closure Stud Bolting AMP (B.2.3.3),
- MNGP BWR Vessel Internals AMP (B.2.3.7)
- MNGP Fire Water System (B.2.3.16)
- MNGP Fuel Oil Chemistry AMP (B.2.3.18)
- MNGP ASME Section XI, Subsection IWE AMP (B.2.3.29)

B.1.2 <u>Method of Discussion</u>

For those MNGP AMPs that are consistent with the AMP descriptions and assumptions made in Sections X and XI of NUREG-2191, or are consistent with exceptions or enhancements, each AMP discussion is presented in the following format:

- A Program Description abstract of the overall program form and function is provided. This Program Description also includes whether the program is existing (and if it replaces LR programs) or new for SLR.
- A NUREG-2191 consistency statement is made about the AMP.
- Exceptions to the NUREG-2191 program are outlined and a justification for the exception(s) is provided.
- Enhancements or additions to make the MNGP AMP consistent with the respective NUREG-2191 AMP are provided. A proposed schedule for completion is discussed. This SLRA defines "enhancements" as any changes to plant programs or activities that need to be implemented in order to align with the guidance of NUREG-2191.
- OE information specific to the AMP is provided.
- A Conclusion section provides a statement of reasonable assurance that the MNGP AMP for SLR is effective or will be effective when implemented if new or enhanced.

B.1.3 <u>Quality Assurance Program and Administrative Controls</u>

The MNGP QA Program for MNGP implements the requirements of 10 CFR Part 50, Appendix B, *Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants*, 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 MNGP QA Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the SR and NSR SSCs and commodity groups that are included within the scope of the AMPs. Generically, the three elements are applicable as follows.

<u>Corrective Actions:</u>

The MNGP CAP is applied regardless of the safety classification of the SSC or commodity group. The MNGP CAP requires the initiation of an Action Request (AR) for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction, or loss of function. Site documents that implement AMPs for SLR direct that an AR be prepared in accordance with those procedures whenever non-conforming conditions are found (i.e., the acceptance criteria are not met). Equipment conditions are corrected through the Work Management Process in accordance with plant procedures. The MNGP CAP specifies that for equipment conditions an AR 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 following statement applies to all the MNGP AMPs for SLR:

> *Conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the condition is determined, and that corrective action is taken to preclude recurrence. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented is documented and reported to appropriate levels of management. The corrective action controls of the Quality Assurance Program, as described in the Quality Assurance Topical Report (QATR) NSPM-1, will be used to meet Element 7, Corrective Actions.*

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 MNGP CAP 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 MNGP CAP provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The MNGP CAP 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 a causal evaluation (CE). The AMPs required for SLR would also result in identification of related unsatisfactory conditions due to ineffective corrective action.

Since the same 10 CFR Part 50, Appendix B, corrective actions, and confirmation process is applied for nonconforming SR and NSR SSCs subject to AMR for SLR, the CAP is consistent with the NUREG-2191 and NUREG-2192 elements.

The following statement is applicable to all the MNGP AMPs for SLR:

> *Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The Quality Assurance Program, as described in the Quality Assurance Topical Report (QATR) NSPM-1, will be used to meet Element 8, Confirmation Process.*
>
> *The confirmation process is part of the corrective action program and includes the following:*
>
> - *Reviews to assure that proposed corrective actions are adequate*
> - *Tracking and reporting of open corrective actions*
> - *Review of corrective action effectiveness*
>
> *Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program. The corrective action program*

constitutes the confirmation process for MNGP aging management programs and activities.

Administrative Controls:

The document control process applies to all generated documents, procedures, and instructions regardless of the safety classification of the associated SSC or commodity group. Document control processes are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. 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 AMP requirements for the purposes of managing the associated aging effects for the SPEO.

The following statement is applicable to all the MNGP AMPs for SLR:

Site QA procedures, review, and approval processes and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The Quality Assurance Program, as described in the Quality Assurance Topical Report (QATR) NSPM-1, will be used to meet the required Administrative Controls.

B.1.4 Operating Experience

Internal OE (also referred to as plant-specific OE) and external OE (also referred to as industry OE) sources are captured and systematically reviewed on an ongoing basis in accordance with the QA program and the MNGP OE program. The MNGP OE program 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.” (Reference 1.6.31)

OE is used at MNGP to enhance existing programs, prevent repeat events, and prevent events that have occurred at other plants. Through INPO, as well as other sources, MNGP receives external OE routinely. The OE process reviews OE from external and internal sources. MNGP personnel screen, evaluate, and act on OE documents and information to prevent or mitigate the consequences of similar events. External OE includes INPO documents, NRC documents (e.g., IN, Regulatory Information Summaries (RISs), GLs, and other documents (e.g., NRC Bulletins). In addition, the SLR interim staff guidance documents are considered as sources of industry OE and evaluated accordingly. Relevant foreign and domestic research and development are also reviewed. Relevant research and development sources include: (a) industry consensus standards development organizations (e.g., ASME, Institute of Electrical and Electronics Engineers, Inc. (IEEE), ACI, API, NACE, International Organization for Standardization); (b) EPRI; (c) generic communications issued by the staff based on research conducted by national labs used by the NRC; and (d) Nuclear Steam Supply System (NSSS) vendor and owner’s groups.

OE, including that involving age-related degradation, is tracked and trended such that adverse trends are entered into the CAP, as appropriate, for evaluation. OE identified as potentially involving aging is evaluated with regard to: (a) SSCs, (b) materials, (c) environments, (d) aging effects, and (e) aging mechanisms, and will also be evaluated with regards to (f) AMPs, and (g) the activities, criteria, and evaluations integral to the elements of the AMPs. AMPs have an established performance feedback mechanism in place by requiring MNGP personnel to use the OE program to evaluate both internal and external OE for applicability. This process provides reasonable assurance that AMPs are informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B. MNGP meets the requirements of NEI 14-13, *Use of Industry Operating Experience for Age-related Degradation and Aging Management Programs* (Reference 1.6.32) regarding the use of industry OE for AMPs

The MNGP OE program meets the requirements of NEI 14-12, *Aging Management Program Effectiveness* (Reference 1.6.33). The MNGP OE program interfaces with and relies on active participation in the INPO OE program, as endorsed by the NRC. MNGP provides training on AMPs, aging concerns, and aging mechanisms during initial and continuing engineering support personnel training. Training on age related degradation and aging management is provided to those personnel responsible for implementing the AMPs and to those who may screen, assign, or evaluate plant-specific and industry OE. Assessments of the effectiveness of the AMPs and activities will be conducted on a periodic basis per NEI 14-12 guidance. The assessments will include evaluation of the AMP or activity against the latest NRC and industry guidance documents and standards that are relevant to the particular program or activity. If there is an indication that the effects of aging are not being adequately managed, then an AR is written and screened, and if a condition adverse to quality exists, a corrective action document is entered into the 10 CFR Part 50, Appendix B, program to either enhance the AMPs or develop and implement new AMPs, as appropriate.

Each AMP summary in this appendix contains a discussion of OE relevant to the AMP. This information was obtained through the review of internal OE captured in a condition report, issue report, OE report, trending report; program assessments; program/system health reports, and through the review of external OE. Additionally, OE was obtained through interviews with site engineers and other plant personnel. New AMPs utilize internal and/or external OE as applicable and discuss the OE and associated corrective actions as they relate to implementation of the new AMP. The OE in each AMP summary may identify 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 SCs within the scope of each AMP will be maintained during the SPEO.

As described above, the existing OE process at MNGP, in conjunction with the CAP, has proven to be effective in learning from adverse conditions and events, and improving programs that address age-related degradation.

B.1.5 Aging Management Programs

Table B-1 lists the MNGP AMPs for SLR in the order that their respective AMP appears in NUREG-2191. Table B-1 states the respective AMP section numbers and whether the AMP is considered a new program or an existing program (or a portion of an existing program) at MNGP. Existing AMPs are based on either an existing LR AMP or existing plant program. Additionally, Table B-2 lists the MNGP AMPs for SLR in alphabetical order. All the AMPs either are or will be consistent with their respective AMPs discussed in NUREG-2191 unless otherwise noted as an exception.

Table B-1
List of MNGP Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
X.M1	B.2.2.1	Fatigue Monitoring	Existing
X.M2	B.2.2.2	Neutron Fluence Monitoring	Existing
X.E1	B.2.2.3	Environmental Qualification of Electric Equipment	Existing
XI.M1	B.2.3.1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing
XI.M2	B.2.3.2	Water Chemistry	Existing
XI.M3	B.2.3.3	Reactor Head Closure Stud Bolting	Existing
XI.M4	B.2.3.4	BWR Vessel ID Attachment Welds	Existing
XI.M7	B.2.3.5	BWR Stress Corrosion Cracking	Existing
XI.M8	B.2.3.6	BWR Penetrations	Existing
XI.M9	B.2.3.7	BWR Vessel Internals	Existing
XI.M12	B.2.3.8	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	New
XI.M17	B.2.3.9	Flow-Accelerated Corrosion	Existing
XI.M18	B.2.3.10	Bolting Integrity	Existing
XI.M20	B.2.3.11	Open-Cycle Cooling Water System	Existing
XI.M21A	B.2.3.12	Closed Treated Water Systems	Existing
XI.M23	B.2.3.13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Existing
XI.M24	B.2.3.14	Compressed Air Monitoring	Existing
XI.M26	B.2.3.15	Fire Protection	Existing
XI.M27	B.2.3.16	Fire Water System	Existing
XI.M29	B.2.3.17	Outdoor and Large Atmospheric Metallic Storage Tanks	New
XI.M30	B.2.3.18	Fuel Oil Chemistry	Existing
XI.M31	B.2.3.19	Reactor Vessel Material Surveillance	Existing
XI.M32	B.2.3.20	One-Time Inspection	New
XI.M33	B.2.3.21	Selective Leaching	Existing
XI.M35	B.2.3.22	ASME Code Class 1 Small-Bore Piping	New

Table B-1
List of MNGP Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.M36	B.2.3.23	External Surfaces Monitoring of Mechanical Components	Existing
XI.M38	B.2.3.24	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	New
XI.M39	B.2.3.25	Lubricating Oil Analysis	Existing
XI.M40	B.2.3.26	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Existing
XI.M41	B.2.3.27	Buried and Underground Piping and Tanks	Existing
XI.M42	B.2.3.28	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	New
XI.S1	B.2.3.29	ASME Section XI, Subsection IWE	Existing
XI.S3	B.2.3.30	ASME Section XI, Subsection IWF	Existing
XI.S4	B.2.3.31	10 CFR Part 50, Appendix J	Existing
XI.S5	B.2.3.32	Masonry Walls	Existing
XI.S6	B.2.3.33	Structures Monitoring	Existing
XI.S7	B.2.3.34	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Existing
XI.S8	B.2.3.35	Protective Coating Monitoring and Maintenance	Existing
XI.E1	B.2.3.36	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Existing
XI.E2	B.2.3.37	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits	Existing
XI.E3A	B.2.3.38	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Existing
XI.E3B	B.2.3.39	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New
XI.E3C	B.2.3.40	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	New
XI.E4	B.2.3.41	Metal-Enclosed Bus	Existing

Table B-1
List of MNGP Aging Management Programs

NUREG-2191 Section	Section	Aging Management Program	Existing AMP or New AMP
XI.E6	B.2.3.42	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Existing

Table B-2
Aging Management Programs

MNGP Aging Management Program	Section	NUREG-2191 Section
10 CFR Part 50, Appendix J	B.2.3.31	XI.S4
ASME Code Class 1 Small-Bore Piping	B.2.3.22	XI.M35
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B.2.3.1	XI.M1
ASME Section XI, Subsection IWE	B.2.3.29	XI.S1
ASME Section XI, Subsection IWF	B.2.3.30	XI.S3
Bolting Integrity	B.2.3.10	XI.M18
BWR Vessel ID Attachment Welds	B.2.3.4	XI.M4
BWR Stress Corrosion Cracking	B.2.3.5	XI.M7
Buried and Underground Piping and Tanks	B.2.3.27	XI.M41
Closed Treated Water Systems	B.2.3.12	XI.M21A
Compressed Air Monitoring	B.2.3.14	XI.M24
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.42	XI.E6
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.36	XI.E1
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements used in Instrumentation Circuits	B.2.3.37	XI.E2
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.39	XI.E3B
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.40	XI.E3C
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.38	XI.E3A
Environmental Qualification of Electric Equipment	B.2.2.3	X.E1
External Surfaces Monitoring of Mechanical Components	B.2.3.23	XI.M36
Fatigue Monitoring	B.2.2.1	X.M1
Fire Protection	B.2.3.15	XI.M26
Fire Water System	B.2.3.16	XI.M27
Flow-Accelerated Corrosion	B.2.3.9	XI.M17
Fuel Oil Chemistry	B.2.3.18	XI.M30
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.24	XI.M38

Table B-2
Aging Management Programs

MNGP Aging Management Program	Section	NUREG-2191 Section
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.3.13	XI.M23
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.34	XI.S7
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.28	XI.M42
Lubricating Oil Analysis	B.2.3.25	XI.M39
Masonry Walls	B.2.3.32	XI.S5
Metal-Enclosed Bus	B.2.3.41	XI.E4
Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B.2.3.26	XI.M40
Neutron Fluence Monitoring	B.2.2.2	X.M2
One-Time Inspection	B.2.3.20	XI.M32
Open-Cycle Cooling Water System	B.2.3.11	XI.M20
Outdoor and Large Atmospheric Metallic Storage Tanks	B.2.3.17	XI.M29
Protective Coating Monitoring and Maintenance	B.2.3.35	XI.S8
Reactor Vessel Internals	B.2.3.7	XI.M16A
Reactor Head Closure Stud Bolting	B.2.3.3	XI.M3
Reactor Vessel Material Surveillance	B.2.3.19	XI.M31
Selective Leaching	B.2.3.21	XI.M33
Structures Monitoring	B.2.3.33	XI.S6
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B.2.3.8	XI.M12
Water Chemistry	B.2.3.2	XI.M2

B.2 Aging Management Programs

B.2.1 NUREG-2191 Aging Management Program Correlation

The correlation between the NUREG-2191 (Generic Aging Lessons Learned (GALL-SLR)) programs and the MNGP AMPs is shown below. Links to the sections describing the MNGP NUREG-2191 programs are provided.

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	MNGP Aging Management Program
X.M1	Fatigue Monitoring	Fatigue Monitoring (B.2.2.1)
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring (B.2.2.2)
X.S1	Concrete Containment Unbonded Tendon Prestress	Not Applicable (MNGP does not have a prestressed concrete containment.)
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (B.2.2.3)
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1)
XI.M2	Water Chemistry	Water Chemistry (B.2.3.2)
XI.M3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting (B.2.3.3)
XI.M4	BWR Vessel ID Attachment Welds	BWR Vessel ID Attachment Welds (B.2.3.4)
XI.M7	BWR Stress Corrosion Cracking	BWR Stress Corrosion Cracking (B.2.3.5)
XI.M8	BWR Penetrations	BWR Penetrations (B.2.3.6)
XI.M9	BWR Vessel Internals	BWR Vessel Internals (B.2.3.7)
XI.M10	Boric Acid Corrosion	Not Applicable (MNGP is not a PWR.)
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 (MNGP is not a PWR.)
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.3.8)
XI.M16A	PWR Vessel Internals	Not Applicable (MNGP is not a PWR.)
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.2.3.9)
XI.M18	Bolting Integrity	Bolting Integrity (B.2.3.10)
XI.M19	Steam Generators	Not Applicable (MNGP is not a PWR.)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	MNGP Aging Management Program
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.2.3.11)
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems (B.2.3.12)
XI.M22	Boraflex Monitoring	Not Applicable (MNGP does not use Boraflex in the spent fuel storage 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 (B.2.3.13)
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring (B.2.3.14)
XI.M25	BWR Reactor Water Cleanup System	Not Applicable (MNGP does not have any components within the XI.M25 AMP scope.)
XI.M26	Fire Protection	Fire Protection (B.2.3.15)
XI.M27	Fire Water System	Fire Water System (B.2.3.16)
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17)
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry (B.2.3.18)
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance (B.2.3.19)
XI.M32	One-Time Inspection	One-Time Inspection (B.2.3.20)
XI.M33	Selective Leaching	Selective Leaching (B.2.3.21)
XI.M35	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping (B.2.3.22)
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components (B.2.3.23)
XI.M37	Flux Thimble Tube Inspection	Not Applicable (MNGP is not a PWR.)
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (B.2.3.25)
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (B.2.3.26)
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks (B.2.3.27)
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 (B.2.3.28)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	MNGP Aging Management Program
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE (B.2.3.29)
XI.S2	ASME Section XI, Subsection IWL	Not Applicable (MNGP has a Mark I steel containment.)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (B.2.3.30)
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J (B.2.3.31)
XI.S5	Masonry Walls	Masonry Walls (B.2.3.32)
XI.S6	Structures Monitoring	Structures Monitoring (B.2.3.33)
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.3.34)
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance (B.2.3.35)
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 (B.2.3.36)
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 (B.2.3.37)
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 (B.2.3.38)
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 (B.2.3.39)
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 (B.2.3.40)
XI.E4	Metal-Enclosed Bus	Metal-Enclosed Bus (B.2.3.41)

Table B-3
Correlation with NUREG-2191 Aging Management Programs

NUREG-2191 Section	NUREG-2191 Aging Management Program	MNGP Aging Management Program
XI.E5	Fuse Holders	Not Applicable (MNGP does not have any components within the XI.E5 AMP scope.)
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 (B.2.3.42)
XI.E7	High-Voltage Insulators	Not Applicable (MNGP does not have any components within the XI.E7 AMP scope.)
MNGP Plant-Specific Program	MNGP does not have a plant-specific AMP.	Not Applicable.

Table B-4
MNGP Aging Management Program Consistency with NUREG 2191

MNGP Aging Management Program	Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements?	Exceptions?
Fatigue Monitoring	B.2.2.1	X.M1	Yes	No
Neutron Fluence Monitoring	B.2.2.2	X.M2	No	No
Environmental Qualification of Electric Equipment	B.2.2.3	X.E1	Yes	No
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B.2.3.1	XI.M1	No	No
Water Chemistry	B.2.3.2	XI.M2	No	Yes
Reactor Head Closure Stud Bolting	B.2.3.3	XI.M3	Yes	Yes
BWR Vessel ID Attachment Welds	B.2.3.4	XI.M4	No	No
BWR Stress Corrosion Cracking	B.2.3.5	XI.M7	No	No
BWR Penetrations	B.2.3.6	XI.M8	No	No
BWR Vessel Internals	B.2.3.7	XI.M9	Yes	Yes
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B.2.3.8	XI.M12	No (New)	No
Flow-Accelerated Corrosion	B.2.3.9	XI.M17	Yes	No
Bolting Integrity	B.2.3.10	XI.M18	Yes	No
Open-Cycle Cooling Water System	B.2.3.11	XI.M20	Yes	No
Closed Treated Water Systems	B.2.3.12	XI.M21A	Yes	No
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.2.3.13	XI.M23	Yes	No
Compressed Air Monitoring	B.2.3.14	XI.M24	Yes	No
Fire Protection	B.2.3.15	XI.M26	Yes	No
Fire Water System	B.2.3.16	XI.M27	Yes	Yes
Outdoor and Large Atmospheric Metallic Storage Tanks	B.2.3.17	XI.M29	No (New)	No
Fuel Oil Chemistry	B.2.3.18	XI.M30	Yes	Yes
Reactor Vessel Material Surveillance	B.2.3.19	XI.M31	Yes	No
One-Time Inspection	B.2.3.20	XI.M32	No (New)	No
Selective Leaching	B.2.3.21	XI.M33	Yes	No

Table B-4
MNGP Aging Management Program Consistency with NUREG 2191

MNGP Aging Management Program	Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements?	Exceptions?
ASME Code Class 1 Small-Bore Piping	B.2.3.22	XI.M35	No (New)	No
External Surfaces Monitoring of Mechanical Components	B.2.3.23	XI.M36	Yes	No
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B.2.3.24	XI.M38	No (New)	No
Lubricating Oil Analysis	B.2.3.25	XI.M39	Yes	No
Monitoring of Neutron-Absorbing Materials Other Than Boraflex	B.2.3.26	XI.M40	No	No
Buried and Underground Piping and Tanks	B.2.3.27	XI.M41	Yes	No
Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B.2.3.28	XI.M42	No (New)	No
ASME Section XI, Subsection IWE	B.2.3.29	XI.S1	Yes	Yes
ASME Section XI, Subsection IWF	B.2.3.30	XI.S3	Yes	No
10 CFR Part 50, Appendix J	B.2.3.31	XI.S4	No	No
Masonry Walls	B.2.3.32	XI.S5	Yes	No
Structures Monitoring	B.2.3.33	XI.S6	Yes	No
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.2.3.34	XI.S7	Yes	No
Protective Coating Monitoring and Maintenance	B.2.3.35	XI.S8	Yes	No
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.36	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.2.3.37	XI.E2	Yes	No

Table B-4
MNGP Aging Management Program Consistency with NUREG 2191

MNGP Aging Management Program	Section	NUREG-2191 Comparison		
		NUREG-2191 Section	Enhancements?	Exceptions?
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.38	XI.E3A	Yes	No
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.39	XI.E3B	No (New)	No
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.40	XI.E3C	No (New)	No
Metal-Enclosed Bus	B.2.3.41	XI.E4	Yes	No
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B.2.3.42	XI.E6	Yes	No

B.2.2 NUREG-2191 Chapter X Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter X AMPs associated with TLAAs at MNGP.

B.2.2.1 Fatigue Monitoring

The MNGP Fatigue Monitoring AMP is an existing preventive AMP that manages fatigue damage of RPV components, RCPB piping components, and other components. This AMP provides an acceptable basis for managing fatigue of components that are subject to fatigue or cycle-based TLAAs or other analyses that assess fatigue or cyclical loading.

The Fatigue Monitoring AMP monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the CUF and CUF_{en} for each analyzed component does not exceed the applicable limit through the SPEO. The program monitors and tracks the number of thermal and pressure transients as specified in USAR Table 4.2-1.

Examples of cycle-based fatigue analyses for which this AMP is used include, but are not limited to: (a) CUF analyses or their equivalent that are performed in accordance with the ASME Code requirements for specific mechanical components; (b) fatigue analysis calculations for assessing environmentally-assisted fatigue (EAF); (c) ASME Class 1 fatigue waivers; (d) implicit fatigue analyses, as defined in the ANSI B31.1 design code or ASME Code Section III rules for Class 2 and 3 components. The MNGP Fatigue Monitoring AMP verifies the continued acceptability of existing analyses through manual cycle counting for monitoring CUFs for the selected component locations using cycle-based fatigue monitoring. MNGP does not use a computer software package or an on-line fatigue monitoring program to demonstrate the ability of components with a calculated CUF to withstand the cyclic loads associated with plant transient operations.

This program provides reasonable assurance that the number of occurrences of each design transient remains within the limits of the component fatigue analyses, which in turn provides reasonable assurance that the analyses remain valid. CUF is a computed parameter used to assess the likelihood of fatigue damage in components subjected to cyclic stresses. Crack initiation is assumed to begin in a mechanical component when the CUF at a point on or in the component reaches the value of 1.0, which is the ASME Code Section III design limit on CUF values. In order not to exceed the design limit on CUF, the procedures that implement the AMP monitor the number of transient occurrences (i.e., design cycles). SLRA Sections 4.3.3, 4.3.4, and 4.3.5 provide details of the evaluation of fatigue for MNGP Class 1 components that have a calculated CUF. As shown in SLRA Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound the projected cycles for the 80-year SPEO. All Class 1 component CUF values remain less than 1.0 for the SPEO.

CUF_{en} is CUF adjusted to account for the effects of the reactor water environment on component fatigue life. For MNGP to ensure that all potential limiting component locations are captured, all the RCPB components with existing ASME Code fatigue analyses, including those MNGP plant-specific NUREG/CR-6260 locations, have been evaluated for EAF. SLRA Section 4.3.7 provides details of the evaluation for environmentally-assisted fatigue for the MNGP SPEO. The effects of fatigue on the intended functions of the ASME Code, Section III components listed in Table 4.3.7-1 that have a calculated CUF_{en} value less than 1.0 will be managed by this AMP through the use of cycle counting and taking required actions prior to exceeding design limits that would invalidate their conclusions. Validation of chemistry parameters that are used as inputs to the environmentally-assisted fatigue analysis will be performed by the Water Chemistry AMP (B.2.3.2).

When a CUF or CUF_{en} value is projected to exceed the allowable limit, corrective action is taken to review the applicable fatigue analyses and take appropriate actions to prevent exceeding the limit. Plant management is notified in accordance with the program procedural requirements, and the condition is entered into the CAP. Component reevaluation, enhanced inspection, repair, or replacement is required to demonstrate that the fatigue design limit will not be exceeded during the SPEO.

NUREG-2191 Consistency

The MNGP Fatigue Monitoring AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section X.M1, *Fatigue Monitoring*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Fatigue Monitoring AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Update Fatigue Monitoring AMP governing plant procedures to provide procedural direction to require periodic validation of chemistry parameters that are used as inputs to determine F_{en} factors.
3. Parameters Monitored or Inspected	Update the Fatigue Monitoring AMP governing plant procedure to identify and require monitoring of the 80-year plant design cycles, or projected cycles that are utilized as inputs to component CUF_{en} calculations, as applicable.

Element Affected	Enhancement
5. Monitoring and Trending	Update the Fatigue Monitoring AMP governing plant procedure to identify the corrective action options to take if the values assumed for fatigue parameters are approached, transient severities exceed the design or assumed severities, transient counts exceed the design or assumed quantities, transient definitions have changed, unanticipated new fatigue loading events are discovered, or the geometries of components are modified.
5. Monitoring and Trending	Update the Fatigue Monitoring AMP governing plant procedure to require trending be performed to ensure that the fatigue parameter limits will not be exceeded during the SPEO.
7. Corrective Actions	Update the Fatigue Monitoring AMP governing plant procedure to specify that acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design limit will not be exceeded during the SPEO. For CUF_{en} analyses, scope expansion includes consideration of other locations with the highest expected CUF_{en} values.

Operating Experience

<u>Industry Operating Experience</u>

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. For example:

- Recent domestic and international fatigue test data show that the light water reactor (LWR) environment can have a significant impact on the fatigue life of carbon and low-alloy steels, austenitic stainless steel, and nickel-chromium-iron (Ni-Cr-Fe) alloys. NRC RG 1.207 describes the methods that the staff considers acceptable for use in performing fatigue evaluations, considering the effects of LWR environments on carbon and low-alloy steels, austenitic stainless steels, and Ni-Cr-Fe alloys. Specifically, these methods include calculating the fatigue usage in air using ASME Code analysis procedures, and then employing the environmental correction factor (F_{en}), as described in NUREG/CR-6909, Revision 1. For MNGP, the methodology described in NUREG/CR-6909, Revision 1 was utilized in calculating the F_{en} values for the SPEO.
- NRC Regulatory Issue Summary 2008-30, *Fatigue Analysis of Nuclear Power Plant Components* was issued to address a concern regarding the

methodology used by some license renewal applicants to demonstrate the ability of nuclear power plant components to withstand the cyclic loads associated with plant transient operations for the PEO. This particular analysis methodology involves the use of the Green's (or influence) function to calculate the fatigue usage during plant transient operations such as startups and shutdowns. MNGP has not used this simplified methodology to calculate fatigue usage.

- NRC Regulatory Issue Summary 2011-14, *Metal Fatigue Analysis Performed by Computer Software* was issued to address concerns with using computer software packages to demonstrate compliance with Section III, *Rules for Construction of Nuclear Facility Components*, of the ASME Code. RIS 2011-14 addressed several issues that came up during an NRC audit of the AP1000 plant analysis performed using WESTEMS computer software with follow-up audits of the application of the software in design and monitoring modes for the Salem LRA. MNGP evaluated this RIS which determined that it does not affect manual cycle counting performed at MNGP, and software such as FatiguePro is not used.

Plant-Specific Operating Experience

- In 2010, while evaluating fatigue calculations, some of the CUF values predicted for the EOL (2030) in one calculation did not correlate as expected to the CUF values for 2030 in the other calculations. These variations were evaluated and the high conservatism in the CUF calculations was reconciled between the calculations.
- In order to continue to take credit for implementing NUREG-6260, MNGP needed to obtain vendor support to accurately model all components. An Engineering Change was performed to update the fatigue usage formulas to incorporate the effects of environmentally-assisted fatigue as well as the calculated effect of EPU.
- In 2010, it was determined that rapid cycling fatigue accumulation for Feedwater nozzles during operation at 10 percent power was not previously calculated. Even though the additional fatigue accumulation on the nozzles was small, this additional fatigue was added to the CUF for the nozzles. Fatigue accumulation for extended operation at 10 percent power was added. The results of the evaluation showed that the additional fatigue accumulation was minimized as long as RWCU injection was in service providing additional heat to the Feedwater inlet flow.
- In 2015, MNGP experienced an unintended pressure drop transient during a reactor pressure test. The cause of this transient was human error. The event related to rapid RPV pressure drop was reviewed to determine if any issue exists related to the PTLR and fatigue limits of the reactor pressure vessel (RPV). As long as the temperature associated with RPV pressure remains with the PTLR curve limits, no concern exists for the RPV, and operation has remained within the PT curve limits. A review of the RPV pressure and temperature over the event indicated that the temperature on all applicable areas of the RPV remained constant and within the temperature allowable.

With regard to fatigue limits, no depressurization rate limit exists for the RPV itself or for RPV components or attachments for which transients are analyzed under the Fatigue Monitoring program. However, this event was being conservatively counted in the fatigue usage for applicable RPV components in the cycle fatigue analysis. Significant margin remains in the analysis and no concern exists with the fatigue limits of the RPV as a result of the event.

- In 2021, CUFs for all components monitored under this AMP were updated for the 2019-2021 operating cycle. This is the latest cycle update to date. This evaluation determined if the current and projected CUF for all components are less than 1.0.

  All components were determined acceptable for continued service. All components' CUFs and projected 80-year CUFs and CUF_{en}s are less than 0.777. All plant transients are less than the design allowable described in USAR Table 4.2-1. HWC availability for the 2019-2021 cycle was 99.8 percent and is acceptable.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and one finding was identified related to the MNGP Fatigue Monitoring AMP.

- The Corrective Actions element of the AMP was reviewed. The program follows the corrective action process; however it was updated to reference the CAP process procedure.
- Additionally, a question was raised about whether the Equipment Cycles computation that is performed once per cycle should be performed as a calculation instead of an engineering evaluation. Per station procedures, changes to TLAAs shall be made in accordance with a calculation procedure. This was determined to be a documentation finding only. The evaluation is required to be either prepared or reviewed by an individual qualified to the BWR Reactor Vessel Integrity Program Owner mentor guide. The evaluation is prepared, reviewed, and approved via the Engineering Evaluation process.

The MNGP Fatigue Monitoring AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Fatigue Monitoring AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.2.2 Neutron Fluence Monitoring

The Neutron Fluence Monitoring AMP is an existing condition monitoring program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to 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 components evaluated by these analyses are the reactor pressure vessel shell, welds, and nozzles in the extended beltline region and RVI components subject to a reactor coolant and neutron flux environment which are fabricated from carbon or low alloy steel with stainless steel cladding.

The program verifies the continued acceptability of existing analyses through neutron fluence monitoring, assesses the susceptibility of Reactor Vessel Internals (RVI) components to neutron irradiation-related damage, and determines and monitors the extent of the RPV beltline region. Thus, the program ensures the analyses involving neutron fluence inputs continue to meet the appropriate limits defined in the 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(s), the calculational methods are performed in a manner that is consistent with 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, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*. The methods and assumptions used for the 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/cm^2 (E >1 MeV) at 72 EFPY. The methods for projecting reactor vessel internal component fast neutron fluence values are not governed by regulatory guidance.

For 80 years (72 EFPY), conservatively assuming a 90 percent capacity factor), TransWare RAMA methodology has been used to develop fluence projections for RPV and RVI components, as discussed in Section 4.2.1.

The Neutron Fluence 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 and P-T 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 reflood thermal shock analysis of the RPV, reflood thermal shock analysis of the RPV Core Shroud, RPV thermal limit analysis (operating P-T limits), RPV circumferential weld examination relief, RPV axial weld failure probability, and aging effect assessments for BWR reactor internals that are induced by neutron irradiation exposure mechanisms.

Plant 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 CAP. 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 Reactor Vessel Material Surveillance (B.2.3.19) program, provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

NUREG-2191 Consistency

The MNGP Neutron Fluence Monitoring AMP is consistent without exception to the 10 elements of NUREG-2191, Section X.M2, *Neutron Fluence Monitoring* as modified by SLR-ISG-2021-02-MECHANICAL.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- NRC Regulatory Issue Summary 2014-11, *Information on Licensing Applications for Fracture Toughness Requirements for Ferritic RCPB Components* (Reference ML14149A165), provided industry guidance on the scope of detail of information that should be provided in the reactor vessel facture toughness and associated P-T limits licensing applications to facilitate staff review. A CAP item was initiated to evaluate the industry OE against current equipment and processes. No actions were identified as a result of the OE evaluation and no additional actions were necessary.

- In 2015, a CAP item was initiated to evaluate industry OE concerning NRC approval of BWRVIP-145-A. This technical guidance document performed the evaluation of the Susquehanna Unit 2 Top Guide and Core Shroud Material Sample Using RAMA Fluence Methodology. MNGP performed an OE review of the document and determined no actions were necessary as BWRVIP-145-A was not applicable to MNGP and MNGP does not use the Susquehanna fluence values for any site evaluation/CAs. At the time the OE review was performed MNGP did not use the RAMA methodology. For SLR the RAMA method is approved and is being used in support of the MNGP SLRA.

The above examples provide objective evidence that the program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE.

Plant-Specific Operating Experience

- In April of 2015, a CAP item was initiated to address that the results of the UT Inspection of Core Shroud Welds H1, H2, H3, H4, H5, H6, H7 (horizontal) and V2, V3, V4 (vertical) required additional, plant-specific analysis for acceptance for continued operation. The existing plant-specific analysis based on fluence accumulation and percentage of cracking required revision in accordance with BWRVIP-76-R1-A guidance for acceptance of core shroud integrity, due to indications that had grown, some new flaws were identified, and fluence accumulation that had occurred in the 10 years since the previous shroud UT. The core shroud welds were evaluated with the additional analysis confirming that all core shroud welds were acceptable for continued operation.

- In 2011, a CAP item was initiated to address that an ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program relief request was prepared using code case N702, however the conditions for using this code case were not met. Code case N702 allows for only 25 percent of the nozzles to be inspected provided plant-specific conditions are met. The technical basis for reducing examination scope is based on 40-year design life and negligible fluence at the nozzle. However, MNGP had entered the 20-year PEO and the recirculation inlet (N2) nozzle welds had been exposed to a greater than negligible fluence with the upper portion of the N2 nozzle considered to be within the “beltline” region of the RPV. With the identification of this finding, a condition evaluation was performed which determined that the condition did not pose an adverse impact on plant or public safety. Supplemental information was prepared and provided to the NRC to support the relief request.. The NRC staff authorized the alternative inspections per MNGP relief request RR-002 in a SER dated August 28, 2012 (Reference ML12236A280).

- In 2010, a CAP item was initiated to address identified findings concerning the RPV N2 nozzles not being appropriately considered in the RPV P-T limit curves. The CAP item identifies that recent industry OE identified the finding concerning a lack of clarity in the industry concerning what components are considered for evaluation in the belt line region of the RPV. Since the discovery of this condition, MNGP pursued a PTLR. The MNGP PTLR updated the curves to address the conditions at that time including the additional data from the 300° surveillance capsule pull, the discovery of the N2 nozzles in the beltline and the extension of the beltline up into the third vessel plate. A conservative administrative limit was placed on the impacted RPV P-T limits curves to account for the impact of the N2 nozzles. The change to the P-T curves and approval of the PTLR was performed under

MNGP License Amendment 172 (Reference ML13025A155). The PTLR was fully implemented, and all procedures were updated to reflect the new curves.

- In 2010, a CAP item was initiated to address that portions of the RPV that were not previously considered as part of the beltline region were now considered part of the RPV beltline. During a review of MNGP vessel fluence reports, the upper-intermediate plate of the reactor vessel was discovered to have entered the beltline (high fluence) region at approximately 12 EFPY. MNGP was at approximately 32 EFPY. Per RG 1.190 all vessel areas considered to be in the beltline region of the vessel should be evaluated for determination of the ART and the effect on P-T curves. Per the CAP item, the upper-intermediate plate had not previously been evaluated for ART and the effect on the P-T curves. Per the CAP item, the discovery had no effect on the site's PT curves as the ART of the upper-intermediate plate was not limiting with respect to the PT curves.

The above examples provide objective evidence that the program monitors and trends neutron fluence to ensure the continued adequacy of the plant-specific analyses, and that findings are entered into the CAP with appropriate actions taken to evaluate and correct findings, as necessary.

- In support of the Neutron Fluence Monitoring program (as part of the Reactor Vessel Material Surveillance program), capsules have been withdrawn from the MNGP RPV, and tested in accordance with 10 CFR Part 50, Appendix H.

  In 1981, the capsule at 30° was removed with one specimen set tested and the second specimen set installed in the Unit 1 Prairie Island Nuclear Generating Plant RPV for continued irradiation at an accelerated fluence. The specimens installed in the Unit 1 Prairie Island Nuclear Generating Plant RPV were removed and tested in 1996. The results of these surveillance specimen evaluations formed the basis for the revised Technical Specification operating limit changes reflected in License Amendment 106 (Reference ML020920252).

  The BWRVIP Integrated Surveillance Program (ISP) which was initiated in 1999 was designed to replace the original plant-specific surveillance capsule programs with representative capsules in host BWR plants. MNGP committed to use the ISP in place of its existing surveillance programs, in the amendment issued by the NRC regarding the implementation of the Boiling Water Reactor Vessel and Internals Project Reactor Pressure Vessel Integrated Surveillance Program. The ISP is described in BWRVIP-86-R1-A: BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan. MNGP is designated as a host plant and has withdrawn and tested capsules in 2007 and 2021.

- Fluence was calculated for the MNGP RPV for the extended 60-year (54 EFPY) licensed operating period, using the methodology of NEDC-32983P, *General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation*, which was approved by the NRC in a letter dated September 14, 2001 (Reference ML072480121) from S.A. Richards (NRC) to J.F. Klapproth (GE). The NRC found that, in general, this methodology adheres to the guidance in RG 1.190 for neutron flux evaluation. The fluence calculation was updated for operation at 2004 MWt using the NEDC-32983P-A methodology and accepted for use by the NRC under license amendment 176 (Reference ML13345A236). Peak fluence was calculated at the RPV inner surface (inner diameter), for purposes of evaluating USE. The value of neutron fluence was also calculated for the 1/4T location into the RPV wall measured radially from the ID, using Equation 3 from Paragraph 1.1 of RG 1.99, Revision 2. This 1/4T depth is recommended in the ASME Boiler and Pressure Vessel Code Section XI, Appendix G, sub-article G-2120, as the maximum postulated defect depth.

This OE provides objective evidence that the program monitors and trends neutron fluence to ensure the continued adequacy of the plant-specific analyses.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the Neutron Fluence Monitoring program (as part of the Reactor Vessel Material Surveillance program). The review concluded that the AMP was found to be effective in managing age-related degradation. Administrative issues associated with the management of the program were identified and were entered the CAP.

The MNGP Neutron Fluence Monitoring AMP is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B, as modified by SLR-ISG-2021-02-MECHANICAL.

Conclusion

The MNGP Neutron Fluence Monitoring AMP provides reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.2.3 Environmental Qualification of Electric Equipment

The MNGP Environmental Qualification of Electric Equipment (EQ) AMP is an existing AMP that manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. The NRC has established nuclear station EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants*.

This AMP provides the requirements for the environmental qualification of electrical equipment important to safety that could be exposed to harsh environment accident conditions as required by 10 CFR 50.49 and RG 1.89, *Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants*. This AMP is established per the requirements of 10 CFR 50.49 to demonstrate that certain electrical components located in harsh plant environments (i.e., those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high-energy line breaks (HELBs), or a main steam line break (MSLB) inside or outside the containment, from elevated temperatures or high radiation or steam, or their combination) are qualified to perform their safety function in those harsh environments after the effects of in-service (operational) aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ, and that the equipment be demonstrated to function in the harsh environment, following aging.

The preventive actions associated with this AMP include the identification of qualified life and specific maintenance/installation requirements to maintain the component within the qualification basis. This AMP provides EQ-related surveillance and maintenance requirements for EQ equipment and monitoring, or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life. Although 10 CFR 50.49 does not require monitoring and trending of EQ equipment, this AMP does provide surveillance and maintenance requirements for the EQ equipment, verifies that the required activities are performed, and tracks and maintains the service life of qualified components. Implementation of this AMP is a coordinated effort from a variety of departments within the MNGP and fleet organization to ensure the continued environmental integrity of specified equipment to remain operable when exposed to a harsh environment. Surveillance and maintenance are performed on all equipment on the EQ list to ensure the equipment remains qualified. The MNGP EQ of Electric Equipment AMP will also provide for visual inspection of accessible, passive EQ equipment at least once every 10 years. This inspection is performed to view the EQ equipment, and also to identify any adverse localized plant environments. An ALE is an environment that exceeds the most limiting qualified condition for temperature or radiation for the component material. An ALE may increase the rate of aging or have an adverse effect on the basis for equipment qualification. EQ electrical equipment may degrade more rapidly than expected when exposed to an ALE.

If monitoring is used to modify a component's qualified life, then appropriate plant-specific acceptance criteria will be established based on applicable 10 CFR 50.49(f) qualification methods. Visual inspection results will show that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate age degradation. An unacceptable indication is defined as a noted condition or situation, that if left unmanaged, could potentially lead to a loss of intended function.

When analysis cannot justify a qualified life in excess of the original PEO and up to the end of the SPEO, then the component parts will be replaced, refurbished, or requalified prior to exceeding the qualified life as required by 10 CFR 50.49. Re- analysis of an aging evaluation addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. The MNGP Environmental Qualification documentation packages are considered TLAAs per 10 CFR 54.21(c)(1).

NUREG-2191 Consistency

The MNGP Environmental Qualification of Electric Equipment AMP, with enhancements, is consistent without exception the 10 elements of NUREG-2191, Section X.E1, *Environmental Qualification of Electric Equipment*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Environmental Qualification of Electrical Equipment AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Visual inspection of accessible, passive EQ equipment will be performed at least once every 10 years with the first periodic visual inspection being performed prior to the SPEO. The purpose of the visual inspection is to identify ALEs that may impact qualified life. Potential ALEs are evaluated through MNGPs CAP.
6. Acceptance Criteria	Document within the visual inspections that accessible passive EQ equipment is free from unacceptable surface abnormalities that may indicate age degradation.

Element Affected	Enhancement
7. Corrective Actions	Evaluate and take appropriate corrective actions, which may include changes to qualified life, when an unexpected ALE or condition is identified during operational or maintenance activities that affect the qualification of electrical equipment.

Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

Industry Operating Experience

EQ programs include consideration of OE to modify qualification bases and conclusions, including qualified life such that the impact on the Environmental Qualification of Electric Equipment program is evaluated and any necessary actions or modifications to the program are performed. Compliance with 10 CFR 50.49 provides reasonable assurance that EQ equipment can perform their intended functions during accident conditions after experiencing the effects of operational aging.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

Plant-Specific Operating Experience

- EQ Program Health Reports:

  3rd Quarter 2020: Due to the revision to the Reactor Building Composite Profiles for Environmental Qualification calculation most of the 86 EQ Files required updating to include the revised accident temperature profiles. The normal temperature calculation was also revised due to changing plant parameters and other corrective actions These program updates can cause additional changes to the downstream EQ Files.

  1st Quarter 2022: To perform a wholesale update of EQ documents, the Corrective Actions Program was used to consolidate all outstanding activities into a single assignment. This issue is planned to be resolved by a long term action plan with established milestones and due dates. The program health color is Red but trending as Improving. Program health is expected to turn green at the end of 2022, reflected in the 1st Quarter 2023 program health report.

- 2017 – Thermography data showed that the recirculation sample line outboard isolation valve’s limit switches and associated conduit seals were

131.6°F and 128.1°F, respectively. This constituted a heat rise of 18.6°F for the limit switches and 15.1°F for the conduit seals (based on the measured ambient temperature of 113°F), which were higher than the ambient temperatures used to evaluate the EQ thermal life of these components.

An evaluation was performed and determined that the limit switches and conduit seals were qualified through the current operating cycle with the limit switch and conduit seals operable-but-nonconforming. The limit switches and conduit seals were replaced in 2019.

- 2017 – The temperature used to calculate the EQ thermal life of the actuators for HPCI steam line isolation valves was determined to possibly be non-conservative due to the potential for heat rise from the steam lines to the actuators. EQ thermal life was based on the normal ambient temperature of 132.37°F and 111°F associated with the steam chase and drywell locations, respectively.

  Since the EQ file did not account for the effects of heat rise on the valves due to process fluid flow, engineering performed a material analysis based on the limiting temperatures obtained. The material analysis showed that the valves were expected to perform their function past the next refueling outage.

  Thermography was performed to obtain actual measure temperatures. Based on an engineering evaluation, cable and internal wiring either have been replaced or will be replaced based on their qualified life.

- 2017 – The EQ actuators on RWCU inlet inboard/outboard isolation valves were susceptible to heat rise from process fluid. These actuators were on a 4 inch line upstream of the cleanup regenerative heat exchanger. The normal inlet temperature of this heat exchanger was 531.5°F.

  EQ Files were updated to include the heat rise due to process fluid.

- 2016 – Heat produced by transformers created localized hot spots in the A and B standby gas treatment panel which were not accounted for within the evaluated ambient temperatures for EQ components. This was observed in two EQ files.

  All equipment within the A and B standby gas treatment panels remained fully qualifiable at the higher temperatures when accounting for localized hot spots. However, these EQ files were nonconforming due to the identified error. The EQ files were updated to reflect new qualified life.

- 2015 – During a 2015 EQ snapshot assessment, two GE cable types were determined to be routed through reactor building HELB volumes associated with the RWCU rooms and were not evaluated for these locations.

  This identified a discrepancy for the EQ qualification documentation for the wires that supply one RHR MOV. The EQ qualification for the wires that supply the valve were adequately bounded by the environmental conditions.

This was a documentation issue that did not impact the operability of the MOV.

- 2015 – During revision of Limitorque and Rotork MOV EQ Files, the estimated cycling of the actuators due to surveillances and normal plant operation was discovered to be non-conservative. The files either estimated one cycle per quarter or one cycle per month. Some quarterly surveillances cycle the actuators multiple times. Additionally, some valves were manipulated in multiple surveillances which resulted in additional cycling. This led to more cycles than what was accounted for in the EQ Files.

  Thus the number of cycles estimated by EQ files was not conservative. These files required revision to include an accurate and bounding estimate of the number of cycles to occur during normal operation. An engineering evaluation provided a conservative estimate of the number of cycles expected to occur during normal operation for the valves qualified. EQ files were updated to include the additional estimated cycles.

- 2012 – The EQ file two fan motors used a radiation qualification value of 1.00×10^6 Rad based on a 20 foot distance from the charcoal filter. This distance was verified to be about 19 feet.

  EQ Files associated with the fan motors and other components identified to be impacted via extent of condition were updated to incorporate the higher radiation levels.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review only for existing license renewal AMPs was completed in March 2020, and no findings were identified related to the MNGP Environmental Qualification of Electrical Equipment AMP.

The MNGP Environmental Qualification of Electrical Equipment AMP is informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Environmental Qualification of Electrical Equipment AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter XI AMPs and any plant-specific AMPs credited for managing the effects of aging at MNGP.

B.2.3.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP is an existing program where inspections identify and correct degradation in ASME Code Class 1, 2, and 3 components and piping. In accordance with 10 CFR 50.55a, the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program plan documenting the examination and testing of Class 1, 2, and 3 components is prepared in accordance with the rules and requirements of ASME Code Section XI, 2007 Edition and Addenda through 2008. This AMP describes the long-term inspection program for Class 1, 2, and 3 components.

The MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP includes Class 1, 2, and 3 pressure-retaining components, and their integral attachments including welds and pressure-retaining bolting. Periodic visual, surface, and volumetric examinations, as supplemented by guidelines of the BWRVIP program documents, and leakage tests are utilized for inspection and testing of in-scope components. These inspections allow for identification and assessment of age-related degradation, as well as establishment of corrective actions.

The MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP identifies and corrects degradation in Class 1, 2, and 3 components and piping. Inspection methods and frequency are determined in accordance with the requirements of Tables IWB-2500-1 (Class 1), IWC-2500-1 (Class 2), and IWD-2500-1 (Class 3). Examinations are scheduled in accordance with the inspection program, as described by IWB-2400, IWC-2400, IWD-2400, or as specified by approved alternatives as outlined in the Fifth Interval ISI Plan.

The ISI of Class 1, 2, and 3 components and integral attachments has been in place since initial operation of the plant and the inspections are conducted as part of the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP based on the current MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program documents. Examinations are performed as specified to identify the overall condition of components and to ensure that any degraded conditions identified are corrected prior to returning the component to service. The MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program documents are updated at the end of the 120-month interval to the latest approved edition of the ASME Code Section XI, identified by 10 CFR 50.55a, eighteen months prior to the end of the 120-month interval. All examinations and inspections performed in accordance with the program plan are documented by records and reports, which are submitted to the NRC as required by IWA-6000.

Inspection results are evaluated by qualified individuals in accordance with ASME Code Section XI acceptance criteria. Components with indications that do not exceed the acceptance criteria are considered acceptable for continued service. Indications that exceed the acceptance criteria are documented and evaluated in accordance with the MNGP CAP. Components will be accepted based on engineering evaluation, repair, replacement, or analytical evaluation in accordance with IWB-3600, IWC-3600, and IWD-3600 for Class 1, 2, and 3 components, respectively. Repairs or replacements are performed in accordance with ASME Code Section XI, Subsection IWA-4000.

NUREG-2191 Consistency

The MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M1, *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- IE Bulletin 80-13, *Cracking in Core Spray Spargers*. This bulletin described instances of cracking in core spray spargers at two BWR facilities. This trend indicated a need for more intensive inspections of these components during subsequent refueling outages. Each BWR facility with an operating license was required at the next schedule and each following refueling outage until further notice to perform a visual inspection of the core spray spargers and the segment of piping between the inlet nozzle and the vessel shroud and to submit a written report of results, including any corrective measures taken.

  Per the MNGP response to IE Bulletin 80-13 (Reference ML113111152), a visual examination of the MNGP core spray sparger and piping system in the reactor vessel was performed in April 1981 during the Spring refueling outage. Evaluation of all examination results revealed no apparent discontinuities. The core spray spargers are included in the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP for ongoing inspections.

  In March 1993, NRC review and approval was requested for the MNGP evaluation for a crack indication that was discovered in the “B” core spray header during the 1993 refueling outage (Reference ML113110883). The design of the fixture utilized to address this “B” core spray header crack was provided for NRC review in June 1994 (Reference ML20073S832) and approved by the NRC in August 1994 (Reference ML20072N480).

- GL 94-03, Intergranular Stress Corrosion Cracking of Core Shrouds in BWR. This GL described NRC concerns related to core shroud cracking that had been identified at several foreign and domestic BWRs and requested that licensees inspect their core shrouds no later than the next scheduled refueling outage, perform safety analyses to support continued operation until inspections were conducted, develop an inspection plan which addresses all shroud welds, develop plans for evaluation and/or repair of the core shroud, and to work closely with the Boiling Water Reactor Owners Group (BWROG) on coordination of inspections, evaluations and repair options for all BWR internals susceptible to IGSCC.

  Per the initial 30 day MNGP response in August 1994 (Reference ML20072M046), inspections of the MNGP core shroud were scheduled for the 1994 refueling outage. The requested safety evaluation was also provided, which determined that MNGP could continue to operate safely until inspections were conducted. Based on the evaluation of the results the MNGP core shroud was determined to be structurally adequate to withstand all DBAs and transient conditions and posed no operational or safety concerns. In January 1995, the NRC confirmed that MNGP had provided the operational, fabrication, and materials related information requested (Reference ML20078E581 and ML20078E585). In addition, the staff noted that MNGP performed the required examinations of the core shroud during the fall 1994 refueling outage. Based on the results of the materials-based structural analysis of the core shroud, the staff concluded that the structural integrity of the core shroud would be maintained for the operating cycle following the fall 1994 refueling outage without any modification of the MNGP core shroud.

- OE23699, *Initiation of Reactor Shutdown required by Technical Specification 3.1.7 Action C.1*. Quad Cities Station indicated that the SLC tank had a pinhole leak that was not determined to make the tank inoperable per ASME Code requirements. The Quad Cities SLC tank was constructed with Type 304 stainless steel. The most likely cause of external SCC is an exposure to chlorides or other halogen containing solution, which can lead to transgranular stress corrosion cracking (TGSCC). The MNGP SLC tank was also made of stainless steel and was susceptible to the same mechanism and was therefore inspected as part of the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP to verify the structural integrity of the tank.

  In April 2010, MNGP submitted a request to apply ASME Code Case N-705 for a crack identified in the SLC tank bottom plate until the necessary repairs occurred in the next refueling outage scheduled for March 2011 (Reference ML100920376). The NRC provided verbal authorization in April 2010 (Reference ML101130510) and full authorization in July 2010 (Reference ML102000672) of the proposed alternative.

- As part of a 2018 self-assessment for outage readiness, INPO ICES reports from 2017 through 2018 were reviewed for applicability to the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP. Items were either determined not applicable to MNGP

ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP or had previously been reviewed for impact.

- As part of the five-year effectiveness review discussed below, proactive OE review occurred for eleven AMPs, including the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP. These reviews included INPO, NRC INs, and NRC LER numbers. Items were either dispositioned as not applicable or additional items were initiated in the CAP to confirm no impact to the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP. This included disposition of INPO ICES 326122, which was related to a dissimilar metal weld flaw on RHR piping at Fitzpatrick Unit 1. As documented in the CAP, MNGP does contain dissimilar welds in the RCPB, including RHR piping. However, due to their design and construction, all dissimilar welds at MNGP are considered Category A welds. Therefore, this OE was not applicable to MNGP.

Plant-Specific Operating Experience

- Owners Activity Reports (OARs) were reviewed over the last six years (2015-2021). For all minor flaws or relevant conditions that required evaluation or repair/replacement activities for continued service, all items were either examined and evaluated as acceptable or appropriate replacements were completed.

- Integrated Inspection reports, which document NRC inspections findings, were reviewed over the last six years (2016-2021). During this period, there were no findings considered non-cited violations (NCVs) that were identified by either the NRC or self-identified by MNGP that were related to the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP.

Program Assessments and Evaluations:

- A self-assessment was completed in May 2010 to evaluate MNGP license renewal (LR) implementation, including review of LR AMPs, testing and inspections, implementing procedures, and assessment of readiness for the NRC LR Phase 2 inspection. With respect to the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP, the inservice inspection plan was determined to be several years out of date. Update of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection plan was tracked via the CAP.

- A self-assessment was completed in September 2019 in preparation for the LR Phase IV NRC inspection. With respect to the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP, the code of record in the USAR-K was out of date based on the ISI-PLAN-5-BASIS. Evaluation and update of the USAR-K requirements were tracked via the CAP.

- A self-assessment was completed in February 2019 in preparation for the 2019 refueling outage NRC ISI Inspection that reviewed the

ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program for deficiencies, verified ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program code compliance, reviewed OE, and verified that industry OE was adequately evaluated and incorporated into the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program. No areas for improvement were identified; however, several enhancements and clarifications to the MNGP ISI fifth Interval Plan were recommended, updated, and tracked via the CAP.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and one finding was identified related to the MNGP ISI AMP. With respect to Element 9 (Administrative Controls), the AMP document required update for information related to the Fifth 10-year Interval Plan, as well as some minor editorial changes. In addition, the USAR-K required related update. These items were identified as UNSAT; however, the AMP effectiveness was not affected.

Program Health Reports:

- Per the ISI program health report (July 2020), the MNGP ISI AMP overall program health color is GREEN and is considered stable. No future changes are expected.

The MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP is informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.2 Water Chemistry

The MNGP Water Chemistry AMP, previously known as the Plant Chemistry Program, is an existing AMP that mitigates the aging effects of loss of material due to corrosion, cracking due to SCC and related mechanisms, and reduction of heat transfer due to fouling in components exposed to treated water environment. The MNGP Water Chemistry AMP relies on monitoring and control of reactor water chemistry based on industry guidelines contained in BWRVIP-190 (EPRI 3002002623) (Reference 1.6.34).

The MNGP Water Chemistry AMP is generally effective in removing impurities from intermediate and high-flow areas; however, NUREG-2191 also identifies those circumstances in which this AMP is to be augmented to manage the effects of aging for SLR. For example, the MNGP Water Chemistry AMP may not be effective in low-flow or stagnant-flow areas. Accordingly, in certain cases as identified in NUREG 2191, verification of the effectiveness of this AMP is undertaken to provide (1) reasonable assurance that significant degradation is not occurring and (2) the component intended function is maintained during the SPEO. For these specific cases, the MNGP One-Time Inspection AMP (B.2.3.20) is used to perform inspections of selected components at susceptible locations in the system to be completed prior to the SPEO. This AMP addresses the metallic components subject to AMR that are exposed to a treated water environment.

The MNGP Water Chemistry AMP includes specifications for chemical species, impurities and additives, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice, and pitting corrosion and cracking caused by SCC. Additives are used for reactivity control and to control pH and inhibit corrosion.

This AMP monitors concentrations of corrosive impurities and water quality in accordance with the EPRI water chemistry guidelines to mitigate loss of material, cracking, and reduction of heat transfer. Chemical species and water quality are monitored by in-process methods and through sampling, and the chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples. Chemistry parameter data are recorded, evaluated, and trended in accordance with the EPRI BWR water chemistry guidelines.

Any evidence of aging effects or unacceptable water chemistry results are evaluated, the cause identified, and the condition corrected. When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range (or to change the operational mode of the plant) within the time period specified in the EPRI BWR water chemistry guidelines.

NUREG-2191 Consistency

The MNGP Water Chemistry AMP is consistent with one exception to the 10 elements of NUREG-2191, Section XI.M2, *Water Chemistry* as modified by SLR-ISG-2021-02-MECHANICAL.

Exceptions to NUREG-2191

The MNGP Water Chemistry AMP includes the following exception to the NUREG-2191 guidance:

(1) Hydrogen peroxide levels are not measured as part of determining electrochemical potential (ECP). Instead, the MNGP Water Chemistry Program uses online noble chemistry and hydrogen water chemistry and maintains chloride and sulfate levels in the reactor coolant as low as possible to achieve mitigation. Mitigation is defined as ECP less than negative 230mV (Standard Hydrogen Electrode, SHE), as determined by plant-specific radiolysis modeling and ECP probes and is based on guidance contained in EPRI BWRVIP-190 (3002002623). Secondary parameters monitored include those identified for an online noble chemistry and hydrogen water chemistry plant for measuring and estimating ECP.

Enhancements

None.

Operating Experience

The MNGP Water Chemistry AMP has been effective at maintaining the desired system water chemistry and detecting abnormal conditions, which have been corrected in an expedient manner. A review of OE supports the above statement as most corrections are related to abnormal chemistry results during operational transients such as startups. Although the abnormal conditions are expected during these transients, the CAP is used for documentation.

The EPRI guidelines for water chemistry are being used and the controlling procedures refer and adhere to the limits specified in them. Over time, this has proven to be an effective method of controlling concentrations of parameters such as sulfates, chlorides, and dissolved oxygen that are detrimental to certain alloys. Controlling these parameters mitigates aging effects in the in-scope components.

Review of plant-specific OE also indicates that the chemistry program is performing its function of mitigating aging effects. A review of corrective action reports from 2012 through 2021 was performed and no reports were found that attributed water chemistry as the cause of component deterioration, aging effects, and/or failing to perform its function. ARs are initiated when water chemistry is found to be out of specification, and most of the instances occur during start-up when parameters are quickly changing and more difficult to control water chemistry. The time durations of out of specification water chemistry are minimal and there is no evidence of having caused detrimental effects on system components.

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- Intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels (SSs) and nickel-base alloys. Significant cracking has occurred in recirculation, CSP, RHR Systems, and RWC System piping welds. IGSCC has also occurred in a number of vessel internal components, including core shroud, access hole cover, top guide, and core spray spargers. No occurrence of SCC in piping and other components in SLC Systems exposed to sodium pentaborate solution has ever been reported.

- MNGP utilizes Hydrogen Water Chemistry (HWC) System to reduce the level of dissolved oxygen in the reactor water by injecting hydrogen into the feedwater. Dissolved hydrogen interacts with dissolved oxygen in the radiation field present in the reactor to lower dissolved oxygen levels in the reactor coolant. The reduction of dissolved oxygen, in combination with high water quality reduces or eliminates IGSCC in primary system piping and improve the resistance to IGSCC in vessel internal components.

Plant-Specific Operating Experience

- In May 2021, the feedwater conductivity level was above BWR Action Level 1 and the feedwater continuous limit level when the reactor power was above 10 percent. Recoating of the condensate demineralizers (CDMs) were in progress when the feedwater conductivity level exceeded the limit levels. Precoating one of the CDMs was performed as soon as possible to drive the feedwater conductivity level below the limit levels, and the other CDM was precoated shortly after and was brought into service to further drive the feedwater conductivity level. The parameter was restored to below the Action Level 1 value.

- In October 2019, dissolved oxygen concentration in the condensate demineralizer effluent and the feedwater trended up and was approaching the BWRVIP-190 Good Practice value. Chemistry was notified of the increasing trend and further samples were taken to ensure the parameters remained within the BWRVIP-190 Good Practice values.

- In September 2018, reactor water conductivity exceeded the BWRVIP-190 BWR Action Level 1 value, and the reactor water dissolved oxygen Good Practice level as a result of an HWC Trip. No action was necessary for exceeding the Good Practice value of reactor water dissolved oxygen. The reactor water conductivity level was continuously measured by in-line instrumentation. The HWC System was restored the same day, and the reactor water conductivity value was brought down below the Action Level 1 value within the allowed time in accordance with BWRVIP-190.

Program Assessments and Evaluations:

- A select AMP effectiveness review was completed in March 2015 to verify the commitments, inspections, and relevant activities were scheduled and performed in accordance with the program. As a result an implementing procedure was revised to include the latest AMP document per procedure change requests.

- A self-assessment was completed in September 2019 in preparation for the LR Phase IV NRC inspection. With respect to the MNGP Water Chemistry AMP, the cited revision of the EPRI BWR Water Chemistry Guidelines was determined to be outdated. The CAP evaluated the USAR-K requirements to document the applicable revision of the EPRI BWR Water Chemistry Guidelines, and the procedures were updated by procedure change requests.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no finding was identified related to the MNGP Water Chemistry AMP.

The MNGP Water Chemistry AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Water Chemistry AMP provides reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.3 Reactor Head Closure Stud Bolting

The MNGP Reactor Head Closure Studs Bolting AMP is an existing AMP for SLR that is related to and implemented by the MNGP ASME Section XI, Subsections IWB, IWC, and IWD portion of the MNGP Inservice Inspection program. This AMP provides (a) ISI in accordance with the requirements of ASME Section XI, Subsection IWB, Table IWB 2500-1; and (b) preventive measures to mitigate cracking. The Reactor Head Closure Studs Bolting AMP will use the edition and addenda of ASME Section XI, 2007 Edition and Addenda through 2008 in accordance with 10 CFR 50.55a. Replacement reactor head studs available for use at MNGP include preventive measures described in RG 1.65, *Material and Inspection for Reactor Vessel Closure Studs*. The scope of this AMP includes:

- Closure head nuts
- Closure studs
- Threads in the RPV flange
- Closure washers and bushings

This AMP provides for condition monitoring of the reactor head closure stud bolting and manages the aging effects of cracking due to SCC or IGSCC and loss of material due to wear or corrosion for reactor head closure stud bolting. This is accomplished through effective monitoring techniques, acceptance criteria, corrective actions, and administrative controls. In accordance with ASME Code Section XI, Subsection IWB categorization and methods for ISI are managed under examination category B-G-1, which includes VT-1 visual inspections of nuts, washers, and bushings, and volumetric exams of studs and threads in flange.

Per MNGPs ISI plan, if bolts or studs are removed for examination, surface examination meeting the acceptance standards of IWB-3515 may be substituted for volumetric examination.

This AMP monitors material conditions and imperfections and detects loss of material by performing visual inspections (VT-1), surface examinations (liquid penetrant and magnetic particle), and volumetric examinations (ultrasonic, radiography and eddy current) in accordance with the requirements specified in Table IWB-2500-1. The specific type of inspection to be performed for each of the different bolting components is listed in the MNGP ISI plan. Components are examined for evidence of operation-induced flaws (cracking, pitting) using volumetric and surface techniques. The VT-1 visual inspection is used to detect cracks, symptoms of wear, corrosion, or physical damage. The extent and frequency of inspections is specified in Table IWB-2500-1, as modified in accordance with the MNGP ISI plan.

Appropriate preventive measures have been used for the reactor head closure stud bolting based on plant-specific OE and best practices.

This AMP ensures that the frequency and scope of examination of the reactor head closure stud bolting is sufficient so that the aging effects are detected before the component(s) intended function(s) would be compromised or lost. Inspections are performed in accordance with the inspection intervals specified by the MNGP ISI plan. These examinations are scheduled in accordance with the MNGP ISI plan and will be continued during the SPEO.

The acceptance criteria associated with this AMP, provided in the MNGP ISI plan, are based on the acceptance standards for the inspections identified in Subsection IWB for the reactor head closure stud bolting. Table IWB-2500-1 identifies references to acceptance standards listed in IWB-3500. When areas of degradation are identified, an engineering evaluation is performed to determine if the component is acceptable for continued service, or if repair or replacement is required in accordance with Subsections IWB, IWA-4000, and IWA 6000. The engineering evaluation includes probable cause, the extent of degradation, the nature and frequency of additional examinations, and whether repair or replacement is required. In addition, the material inspection and maximum yield strength information provided in the regulatory position of RG 1.65 will be included in the program, for completeness, prior to entering the SPEO.

This AMP includes procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi. MNGP procedures include requirements to preclude the use of molybdenum sulfide-containing lubricants.

NUREG-2191 Consistency

The MNGP Reactor Head Closure Stud Bolting AMP, with enhancement, is consistent, with one exception, to the 10 elements of NUREG-2191, Section XI.M3, *Reactor Head Closure Stud Bolting*.

Exceptions to NUREG-2191

NUREG-2191 recommends, as a preventive measure that can reduce the potential for SCC or IGSCC, using bolting material for the reactor head closure studs that have an actual measured yield strength less than 150 ksi for newly installed studs, or less than 170 ksi ultimate tensile strength for existing studs.

Hardness tests conducted on the MNGP reactor vessel closure studs showed that most studs have greater than 170 ksi tensile strength. MNGP performed field hardness testing and UT examination of the reactor head studs removed from the reactor cavity during the 1991 outage, evaluated the test results, and evaluated the original certified material test reports. Therefore, MNGP is taking exception to Element 2, Preventive Actions, and Element 7, Corrective Actions.

This exception is acceptable because MNGP meets all other preventive measures listed in NUREG-2191 AMP XI.M3, *Reactor Head Closure Stud Bolting* that can reduce the potential for cracking are met by the MNGP Reactor Head Closure Stud Bolting AMP. In addition, volumetric examinations that are capable of detecting degradation due to SCC will continue to be performed in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (B.2.3.1) as applicable.

Enhancements

The MNGP Reactor Head Closure Stud Bolting AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions 7. Corrective Actions	Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of newly procured material is limited to a measured yield strength less than 150 ksi.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- NRC IN 2012-20 described an event involving de-tensioned reactor vessel closure head studs at a boiling-water reactor that resulted in leakage from the reactor vessel during startup operations and a manual scram.

  MNGP addressed this information in their CAP. MNGP incorporated several changes to the RPV studs tensioning procedure to enhance and improve their reactor vessel closure head stud tensioning process based on their review of this industry event.

Plant-Specific Operating Experience

- Owners Activity Reports (OARs), which provide overviews of in-service examination results and repair/replacement activities performed during a refueling cycle, were reviewed over the last six years (2015-2021) (Reference ML15239A823, ML17223A091, ML19221B714, and ML21229A092). Each of the summaries included items with flaws or relevant conditions that required evaluation for continued service, as well as repair/replacement activities required for continued service. No flaws or relevant conditions that required evaluation for continued service were identified for the reactor head closure stud bolting.

- Integrated Inspection reports, which document NRC inspections findings, were reviewed over the last six years (2016-2021). During this period, none of the findings were related to the MNGP Reactor Head Closure Stud Bolting AMP.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate.

Program Assessments and Evaluations

- A self-assessment was completed in May 2010 to evaluate MNGP license renewal (LR) implementation, including review of LR AMPs, testing and inspections, implementing procedures, and assessment of readiness for the NRC LR Phase 2 inspection. With respect to the MNGP Reactor Head Closure Stud Bolting AMP, there were no findings or areas for improvement noted.

- A self-assessment was completed in September 2019 in preparation for the LR Phase IV NRC inspection. With respect to the MNGP Reactor Head Closure Stud Bolting AMP, there were no findings or areas for improvement noted.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and no findings were identified related to the MNGP Reactor Head Closure Stud Bolting AMP.

Program Health Reports

Given that the MNGP Reactor Head Closure Stud Bolting AMP is related to and implemented by the MNGP ASME Section XI In-Service Inspection Program the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program health report (July 2020) has been reviewed. The MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection overall program health color is GREEN and is considered stable.

The MNGP Reactor Head Closure Stud Bolting AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Reactor Head Closure Stud Bolting AMP, with one enhancement, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.4 BWR Vessel ID Attachment Welds

The MNGP BWR Vessel ID Attachment Welds AMP is an existing condition monitoring program that manages the aging effect of cracking due to cyclic loading, SCC, and IGSCC of the BWR vessel ID attachment welds exposed to a reactor coolant environment. The MNGP BWR Vessel ID Attachment Welds AMP is implemented through station procedures that provide for mitigation of cracking through management of water chemistry and condition monitoring through examinations of reactor vessel interior attachment welds. The examination categories include volumetric, surface, and visual examination methods.

Under 10 CFR 50.55a relief, examination of BWR vessel ID attachment welds are completed exclusively under the guidance of the BWRVIP program documents in lieu of ASME Section XI requirements, including schedule, extent, frequency, sequence of exams, re-examinations, and additional examinations (Reference ML16208A462). The exams are completed during general overview exams performed on the associated components attached to the RPV. The MNGP BWR Vessel ID Attachment Welds AMP incorporates the inspection and flaw evaluation recommendations of BWRVIP-48-A, *Vessel ID Attachment Weld and Inspection and Flaw Evaluation Guidelines*, and the recommendations for reactor water chemistry as described in the MNGP Water Chemistry AMP (B.2.3.2).

The MNGP BWR Vessel ID Attachment Welds AMP monitors the effects of cracking due to cyclic loading, SCC, and IGSCC by requiring inspections of the reactor vessel interior attachment welds as part of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program and BWRVIP reports. A description of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program, including the controlling edition of ASME Code, Section XI, is provided in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (B.2.3.1).

NUREG-2191 Consistency

The MNGP BWR Vessel ID Attachment Welds AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M4, *BWR Vessel ID Attachment Welds*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- As part of the 2020 five-year effectiveness review discussed below, proactive OE review occurred for eleven AMPs, including the MNGP BWR Vessel ID Attachment Welds AMP. These reviews included INPO, NRC INs, and NRC LER numbers. Items were either dispositioned as not applicable or additional items were initiated in the CAP and confirmed not to have any impact to the MNGP BWR Vessel ID Attachment Welds AMP.

The examples above demonstrate that the MNGP BWR Vessel ID Attachment Welds AMP reviews the need to incorporate applicable industry OE into the AMP. This provides reasonable assurance that the MNGP BWR Vessel ID Attachment Welds AMP will continue to be effective during the SPEO.

Plant-Specific Operating Experience

- Owners Activity Reports (OARs) were reviewed over the last six years (2015-2021). For all minor flaws or relevant conditions that required evaluation or repair/replacement activities for continued service, all items were either examined and evaluated as acceptable or appropriate replacements were completed.

Program Assessments and Evaluations:

- As part of a 2019 self-assessment in preparation for the LR Phase IV NRC inspection, for the MNGP BWR Vessel ID Attachment Welds AMP the USAR-K Section K2.1.11 discussed old revisions of the BWRVIP that did not appear to be updated; however, the BWR Vessel ID Attachment Welds program description had been updated to reflect more recent revision. The USAR-K was updated to match the revisions of the BWRVIP.

- A 2010 self-assessment evaluated MNGP LR implementation, including review of LR AMPs, testing and inspections, implementing procedures, and assessment of readiness for the NRC LR Phase 2 inspection. With respect to the MNGP BWR Vessel ID Attachment Welds AMP, the BWRVIP implementation plan was noted as not being controlled with a formally controlled document. As part of the CAP, the BWRVIP inspection schedule was reviewed for a requirement to be controlled as a controlled document. The BWRVIP was documented as already a controlled document, as well as already being a reference document in the MNGP site document. The BWRVIP document was revised to include the previous inspection cycle data from 2009.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020. The MNGP BWR Vessel ID Attachment Welds AMP was required to be revised due to NRC approval of Relief Request RR-010, as well as minor editorial changes. These items were identified as Unsatisfactory; however, the effectiveness of the AMP was not affected.

The MNGP BWR Vessel ID Attachment Welds AMP is informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP BWR Vessel ID Attachment Welds AMP provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.5 BWR Stress Corrosion Cracking

The MNGP BWR Stress Corrosion Cracking AMP is an existing condition monitoring and mitigative program that manages IGSCC in piping and piping welds made of stainless steel and nickel based alloy that are 4 inches or larger in diameter in reactor coolant greater than 200°F, regardless of code classification. The AMP implements the program delineated in NUREG-0313, Revision 2, and NRC GL 88-01 and its Supplement 1. The program includes preventive measures to mitigate IGSCC, and inspection and flaw evaluation to monitor IGSCC and its effects.

Reactor coolant water chemistry is controlled and monitored in accordance with EPRI guidelines to maintain high water purity and reduce susceptibility to SCC or IGSCC as described in the MNGP Water Chemistry (B.2.3.2) program. All IGSCC susceptible materials have been replaced or protected with a cladding of resistant weld material at MNGP. Therefore, all piping welds are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01. As part of the MNGP recirculation piping replacement effort, austenitic stainless steel portions of piping systems 4 inches in nominal diameter or larger operating at temperatures above 200°F of the RCPB were replaced in accordance with the requirements of NUREG-0313.

The program addresses the management of crack initiation and growth due to IGSCC in the piping, welds, and components through the implementation of the MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.3.1) in accordance with ASME Code, Section XI. Inservice inspections, performed as augmented requirements of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) program, ensure that aging effects are identified and repaired before the loss of intended function of in scope components. Welds classified as IGSCC Category A, which are all welds in the scope of this program, have been subsumed into the Risk Informed In-service Inspection (RI-ISI) program in accordance with staff-approved EPRI Topical Report TR-112657, Revision B-A, Final Report, *Revised Risk-Informed Inservice Inspection Evaluation Procedure*, based on the approved ASME Code relief request RR-003 in 2014. In the event that such relief is not approved by NRC staff for future ISI intervals during the SPEO, Category A welds would be examined per the extent and schedule defined by BWRVIP-75-A.

Inspection and flaw evaluation is conducted in accordance with the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program plan. If a flaw exceeds the applicable acceptance standards of IWB-3500, then the condition is entered into the CAP and an analytical evaluation may be performed in accordance with IWB-3600 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. 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.

NUREG-2191 Consistency

The MNGP BWR Stress Corrosion Cracking AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M7, *BWR Stress Corrosion Cracking*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

In 2017, Limerick Generating Station Unit 2 identified a through-wall leak on a 2-inch water level instrument nozzle penetration. The cause was determined to be IGSCC. This industry LER was evaluated for relevance at MNGP. The AR determined that, due to the design, material, fabrication, and environmental condition created by the modified configuration (creviced location created by a weld defect in the overlay), the instrumentation nozzle related to the Limerick Unit 2 issue is significantly different than the MNGP instrumentation nozzles and that similar conditions do not exist at MNGP. This is supported by OE of defects at only two plants for these partial penetration j-groove welds, both of which were related to IGSCC susceptibility caused by lack of post weld stress relieving activities. No additional actions were necessary from the review of this industry OE.

In 2017, Fitzpatrick Unit 1 identified a rejectable indication on the RHR LPCI Injection Loop. A full structural weld overlay was implemented using material that was IGSSC resistant (Alloy 52M) to arrest crack propagation while establishing a new structural pressure boundary. The direct cause of the indication was IGSCC. The weld was a classified as a Category D weld in accordance with BWRVIP-75 and NRC GL 88-01. Although this OE is not specifically applicable to MNGP as all materials have been replaced for Category A welds, dissimilar metal (DM) welds at similar locations to Fitzpatrick's welds were reviewed to verify that they had been replaced with non-IGSCC susceptible materials and stress improvement applied.

NRC GL 88-01 and NRC INs 82-39, 84-41, and 2004-08 illustrate industry examples of IGSCC in BWR piping made of austenitic stainless steel and nickel alloys. NRC GL 88-01 and NUREG-0313 programs directly address mitigating measures for SCC and IGSCC.

MNGP has fully pursued the actions outlined in NRC GL 88-01 and NUREG-0313 to modify the plant to only have IGSCC Category “A” welds in the scope of the BWR Stress Corrosion Cracking program.

<u>Plant-Specific Operating Experience</u>

There have been no specific issues with IGSCC at MNGP since IGSCC-resistant materials have been exclusively used. MNGP is required to maintain chemistry parameters in order to qualify for inspection relief. A review of "IGSCC Mitigation Status Reports" show no indication of issues with maintaining proper chemistry to mitigate IGSCC. No corrective action items were identified through MNGPs corrective actions program with any examples of IGSCC in Class 1 or Class 2 stainless steel piping components.

Inservice Inspection Owner's Activity Reports for Cycle 25 (2011) and Cycle 26 (2013) were also reviewed for any discussion of indications of IGSCC prior to ASME Code relief request RR-003 being approved in 2014. There were no indications identified.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP BWR Stress Corrosion Cracking AMP.

The MNGP BWR Stress Corrosion Cracking AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP BWR Stress Corrosion Cracking AMP provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.6 BWR Penetrations

The MNGP BWR Penetrations AMP is an existing condition monitoring program that manages the aging effect of cracking due to cyclic loading, SCC, and IGSCC of the BWR instrumentation penetrations, CRD housing and incore-monitoring housing (ICMH) penetrations, and the SLC/core plate differential pressure (dP) nozzle exposed to a reactor coolant environment. The MNGP BWR Penetrations AMP 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 MNGP BWR Penetrations AMP 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 Delta-P Inspection and Flaw Evaluation Guidelines*, and the recommendations for reactor water chemistry as described in the MNGP Water Chemistry AMP (B.2.3.2).

The MNGP BWR Penetrations AMP monitors the effects of cracking due to cyclic loading, SCC, and IGSCC by requiring inspections of the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and SLC/core plate dP nozzle as part of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program per the requirements of ASME Code, Section XI, Table IWB-2500-1 and BWRVIP reports. A description of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program, including the controlling edition of ASME Code, Section XI, is provided in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (B.2.3.1).

NUREG-2191 Consistency

The MNGP BWR Penetrations AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M8, *BWR Penetrations*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- As part of the 2020 five-year effectiveness review discussed below, proactive OE review occurred for eleven AMPs, including the MNGP BWR Penetrations AMP. These reviews included INPO, NRC INs, and NRC LER numbers. Items were either dispositioned as not applicable or additional items were initiated in the CAP and confirmed not to have any impact to the MNGP BWR Penetrations AMP.

The examples above demonstrate that the MNGP BWR Penetrations AMP reviews the need to incorporate applicable industry OE into the AMP. This provides reasonable assurance that the MNGP BWR Penetrations AMP will continue to be effective during the SPEO.

Plant-Specific Operating Experience

- Owners Activity Reports (OARs) were reviewed (2015-2021). For all minor flaws or relevant conditions that required evaluation or repair/replacement activities for continued service, all items were either examined and evaluated as acceptable or appropriate replacements were completed.

Program Assessments and Evaluations:

- A 2010 self-assessment evaluated MNGP LR implementation, including review of LR AMPs, testing and inspections, implementing procedures, and assessment of readiness for the NRC LR Phase 2 inspection. With respect to the MNGP BWR Penetrations AMP, the BWRVIP implementation plan was noted as not being controlled with a formally controlled document. As part of the CAP, the BWRVIP inspection schedule was reviewed for a requirement to be controlled as a controlled document. The BWRVIP was documented as already being controlled as a controlled document, as well as already being a reference document in the MNGP site document. The BWRVIP document was revised to include the previous inspection cycle data from 2009.

- As part of a 2019 self-assessment in preparation for the LR Phase IV NRC inspection, for the MNGP BWR Penetrations AMP the USAR-K Section K2.1.9 discussed old revisions of the BWRVIP that did not appear to be updated; however, the BWR Penetrations program description had been updated to reflect more recent revision. The USAR-K was updated to match the revisions of the BWRVIP.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020. The MNGP BWR Penetrations AMP was required to be revised for minor editorial changes with respect to Element 9 (Administrative Controls). This item was identified as Satisfactory.

The MNGP BWR Penetrations AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP BWR Penetrations AMP provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.7 BWR Vessel Internals

The BWR Vessel Internals AMP is an existing condition monitoring and mitigative program that includes inspections and flaw evaluations in conformance with the guidelines of applicable staff-approved BWRVIP documents and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel.

Available industry guidance includes time-dependent assumptions regarding component degradation mechanisms which have only been evaluated for 60 years of operation. To address this, NUREG-2192 includes three further evaluation items for an SLR applicant to address regarding BWR reactor vessel internals components aging mechanisms (3.1.2.2.12 through 3.1.2.2.14). In response, the BWRVIP developed BWRVIP-315 to disposition these further evaluations and identify any necessary plant-specific evaluations. For MNGP, there are no additional components subject to degradation mechanisms for SLR. However, to implement the guidance in BWRVIP-315, some BWRVIP guidance documents require enhancement and revision (as shown in BWRVIP-315) in order to address operation beyond 60 years. These are documented in Appendix C. The MNPG BWR Vessel Internals AMP recognizes the BWRVIP SLR guidance continues to develop and will continue to implement the most recent NRC-approved versions of the BWRVIP guidance.

The BWR Vessel Internals AMP manages the effects of cracking due to SCC, IGSCC, or 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 includes inspection and flaw evaluation in conformance with the guidelines of applicable BWRVIP reports and ASME Code, Section XI. The program mitigates these effects by managing water chemistry per the Water Chemistry (B.2.3.2) program.

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable staff-approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB-2500-1. The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components. This program also manages loss of preload for jet pump assembly hold-down beam bolts by performing visual inspections or stress analyses for adequate structural integrity.

The program utilizes the following BWRVIP guidelines for inspection, evaluation, and repair recommendations for the components listed. If a new or revised BWRVIP guideline approves a less conservative requirement than the staff-approved version, the more restrictive requirement is followed until the staff approves the new or revised guideline.

<u>Core Shroud</u>: Inspections and flaw evaluations are performed in accordance with BWRVIP-76-A, Revision 1-A. The repair design criteria in BWRVIP-02-A, Revision 2, would be utilized in preparing a repair plan for the core shroud.

Core Plate: BWRVIP-25 Revision 1-A concludes that cracking due to fatigue is not an aging effect that requires management for the core plate. Repairs would be performed using the guidance from BWRVIP-50-A.

Core Spray: Inspections and evaluations are performed in accordance with BWRVIP-18, Revision 1-A. The repair design criteria in BWRVIP-16-A and BWRVIP-19-A would be used in preparing a repair plan for CSP System components that are internal to the reactor vessel.

Shroud Support: Inspections and evaluations are performed in accordance with approved relief request RR-008, Alternative to IWB-2420(b) as applied to the flaws in Shroud Support Plate Welds H8 and H9. The BWRVIP credits overview examinations performed during BWRVIP examinations under BWRVIP-38 in lieu of B-N-1, reactor vessel interior examinations. Repair design criteria in BWRVIP-52-A would be used in preparing a repair plan for the shroud support.

Jet Pump Assembly: Inspections and evaluations are performed in accordance with BWRVIP-41, Revision 3, and BWRVIP-138-R1-A. The repair design criteria in BWRVIP-51-A would be used in preparing a repair plan for jet pump components.

Low-pressure coolant injection (LPCI) Coupling: MNGP reactor vessel internals do not include a LPCI coupling therefore Inspections, flaw evaluations, and repairs performed in accordance with BWRVIP-42-A and BWRVIP-56-A do not apply.

Top Guide: Inspections and evaluations are performed in accordance with BWRVIP-26-A and BWRVIP-183. The repair design criteria in BWRVIP-50-A would be utilized in preparing a repair plan for the top guide. MNGP is committed to the inspection of guide grid beams in accordance with BWRVIP-183. Ten percent of the grids beam cells containing control rod blades are inspected every 12 years, with at least five percent inspected within six years of the start of the BWRVIP-183 inspection cycle. Inspections are performed using the EVT-1 method. This inspection schedule will continue through the SPEO.

Control Rod Drive (CRD) Housing and Lower Plenum Components: Inspections and evaluations are performed in accordance with BWRVIP-47-A. The inspections required by BWRVIP-47-A relative to CRD housings are further discussed in the BWR Penetrations (B.2.3.6) program. The repair design criteria in BWRVIP-55-A would be utilized in preparing a repair plan for the control rod drive housings.

Steam Dryer: MNGP replaced its original steam dryer with a Westinghouse Nordic design steam dryer in 2011. The Nordic steam dryer configuration is not listed in BWRVIP-139. MNGP inspects the steam dryer in accordance with the inspection guidance provided in the requirements of the Long-Term Steam Dryer Inspection Plan approved by the NRC by letter dated August 5, 2020 (Reference ML20202A230). Further discussion is provided in Exception 1 below.

Access Hole Covers: Inspections and evaluations are performed in accordance with BWRVIP-180. The repair design criteria in BWRVIP-217 would be utilized in preparing a repair plan for the access hole covers.

The BWR Vessel Internals program specifies the necessary examinations to be performed during each outage based on the BWRVIP guidelines. BWRVIP-03 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.

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 flaw 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 is used for weld repairs of irradiated structural components.

BWRVIP License Renewal Applicant Action Items listed in the NRC SERs for BWRVIP reports are addressed in Appendix C.

NUREG-2191 Consistency

The MNGP BWR Vessel Internals AMP, with enhancement, will be consistent with one exception to the 10 elements of NUREG-2191, Section XI.M9, *BWR Vessel Internals*.

Exceptions to NUREG-2191

The MNGP BWR Vessel Internals AMP includes the following exception to the NUREG-2191 guidance:

(1) MNGP replaced its original steam dryer with a Westinghouse Nordic design steam dryer in 2011. The Nordic steam dryer configuration is not listed in BWRVIP-139. MNGP inspects the steam dryer in accordance with the inspection guidance provided in the requirements of the Long-Term Steam Dryer Inspection Plan, approved by the NRC by letter dated August 5, 2020 (Reference ML20202A230).

Justification for Exception: The visual inspection results from the first two scheduled refueling outages in RFO 28 (2017) and RFO 29 (2019) after reaching full EPU conditions represent the baseline inspection results for the MNGP replacement steam dryer. The licensee conducted visual inspections of all accessible locations of the steam dryer using general principles and guidance in BWRVIP-139-A. There were no relevant indications from these two inspections.

The long-term inspection plan includes inspection of the various locations over ten-year periods. This frequency is consistent with the re-inspection frequency of BWRVIP-139 and Westinghouse recommendations.

Over the ten-year periods, the plan requires inspection of:

- all inspection locations in accordance with Westinghouse Letter, LTR-A&SA-12-8, Revision 1, Attachment B, *Westinghouse Recommendations for Inspections of the Monticello Replacement Steam Dryer*, (Reference ML12298A033)
- all flaws found during inspections in accordance with BWRVIP-139-1A re-inspection recommendations, and
- the maximum stress location in accordance with Westinghouse recommendations.

The plan also provides subsequent re-inspection guidelines.

Based on its review the NRC found the plan acceptable.

Enhancements

Element Affected	Enhancement
1. Scope of Program	Continue to implement the most recent NRC-approved versions of BWRVIP guidance, specifically BWRVIPs -26-A, -41-R4-A, -47-A, and -183-A as indicated in BWRVIP-315.

Operating Experience

Industry Operating Experience

- There is documentation of cracking in both the circumferential and axial core shroud welds, and in shroud supports.
- Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) have been observed in the shroud support access hole covers that are made from Alloy 600.
- Instances of cracking in core spray spargers have been reviewed in NRC Inspection and Enforcement Bulletin (IEB) 80-13, and cracking in core spray pipe has been reviewed in BWRVIP-18, Revision 1-A.

- Cracking of the core plate has not been reported, but the creviced regions beneath the plate are difficult to inspect. Only inspection of core plate bolts (for plants without retaining wedges) or inspection of the retaining wedges is required. NRC IN 95-17 discusses cracking in top guides of United States and overseas BWRs.
- Instances of cracking have occurred in the jet pump assembly (NRC IEB 80-07), hold-down beam (NRC IN 93-101), and jet pump riser pipe elbows (NRC IN 97-02). Cracking of dry tubes has been observed at 14 or more BWRs. The cracking is intergranular and has been observed in dry tubes without apparent sensitization, suggesting that IASCC may also play a role in the cracking.
- Two control rod drive mechanism lead screw male couplings were fractured in a PWR, designed by Babcock & Wilcox, at Oconee Nuclear Station, Unit 3. The fracture was due to thermal embrittlement of 17-4 precipitation-hardened (PH) material (NRC IN 2007-02).
- IGSCC in the X-750 materials of a tie rod coupling and jet pump hold-down beam was observed in a domestic plant.

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

<u>Plant-Specific Operating Experience</u>

The in-vessel visual inspection of reactor pressure vessel internal components during the refueling outage (RFO) from April-May 2017 identified the following results:

- Examinations of the Core Spray piping welds revealed no relevant indications except for the indication monitoring examination of the weld at 80° which showed no significant change in the previously identified indication at that location.

- During examinations of the wedge interface on a jet pump, an indication in the hard surfacing was identified. Examinations of the remaining wedge bearing surfaces revealed no relevant indications. Examinations of the jet pump welds on the diffusers, adapters, inlet mixers, and primary and secondary riser braces, as well as examinations of the sensing lines revealed no relevant indications.

- Monitoring examination of the access hole cover at the 0° location revealed no significant changes in the previously identified indications at that location. The appearance of the indication on the access hole cover 180° location appeared to be dissipating and may have been an artifact from oxide deposits that have changed since the last RVI inspection in 2015 due to the application of online noble chemistry (OLNB), which monitors chemistry parameters to ensure the hydrogen water chemistry program is implemented in accordance with BWRVIP-62-A However, the program engineer determined the indication would continue to be monitored until additional measures could be implemented to further characterize this indication.

- The outer, middle, and inner hood vane bank top plate to perforated plate welds were not visible and could not be examined, and there were no welds found at the lifting eye to rod location. The outer hood to vane bank welds, A1-V1a and A1-V1b were not accessible for examination due to the configuration of the outer hood. Examinations of the remaining replacement steam dryer welds on both the exterior and the interior of the replacement steam dryer revealed no relevant indications. Additional inspections on the replacement steam dryer during the following outage did identify relevant indications as discussed below.

- Examinations of the shroud support plate to shroud weld and the shroud support plate to RPV weld conducted from above the shroud support plate revealed no relevant indications. Monitoring examinations of specific known indications on the weld shroud support plate to shroud weld and the shroud support plate to RPV weld conducted from below the shroud support plate at 68° and 218° for the support plate to shroud weld and 142° and 292° for the shroud support plate to RPV weld revealed no significant changes. General monitoring examinations of segments of H8 and H9 from below the shroud support plate through the remaining Jet Pump segments revealed no significant changes to the known general conditions of the H8 and H9 welds at those locations.

- Monitoring examination of the welds at the several jet pump locations revealed no significant changes; however, most of the indications are becoming less distinct and the indications on the welds at the five locations no longer appeared relevant. Examinations of the two welds revealed no relevant indications.

- Locations with no relevant indications included:
  - the core spray sparger welds, nozzle and drain plug welds, and the sparger brackets,
  - feedwater sparger A, B, C, and D headers and the associated end brackets and pins,
  - top guide grid beams,
  - fuel support castings,
  - steam separator mid-support ring gussets, top support ring gussets, stand pipe welds and 4 shroud head bolt pin windows,
  - shroud vertical welds

The in-vessel visual inspection of reactor pressure vessel internal components during the refueling outage in 2019 identified two relevant indications on the replacement steam dryer. Both indications were in the base metal of the inner hood. Evaluation by the OEM judged that the root cause of the indications is SCC due to cold work from surface grinding. However, a separate evaluation was performed to evaluate potential extension of the indications due to high cycle fatigue. Based on the results of the evaluation extension by fatigue was determined to be unlikely. This is consistent with field experience with this dryer design where no fatigue cracking has been observed. Visual inspections of the indications were recommended after the next two operating cycles (4 years) to determine the length and to verify that crack extension, if any, is acceptable.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and one finding was identified related to the MNGP BWR Vessel Internals AMP. The finding was related to the AMP basis document and USAR Appendix K (USAR-K) not fully aligned and resulted in the following actions:

- The current AMP was updated with information related to the new steam dryer, but USAR-K did not have the information added and was updated.
- The AMP was revised to note that, under the regulatory provisions for the fifth ISI Interval Plan, Relief Request RR-010 (Reference ML15324A305) was approved by the NRC permitting the examinations to be performed using BWRVIP guidelines. USAR-K had a brief statement added regarding use of BWRVIP guidance documents for implementation.
- The AMP did not have a figure for "Material Environments/Aging Effects," which is typically Figure 5.2. This was added to the program.

The effectiveness of the BWR Vessel Internals program was determined to be acceptable.

The MNGP BWR Vessel Internals AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP BWR Vessel Internals AMP provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP is a new condition monitoring program that will provide assurance that RCPB CASS components with the potential for significant thermal aging embrittlement continue to meet their specified intended functions. The RCS 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. The MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.3.1) that implements Subsection IWB requirements will be augmented as necessary by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program which will monitor the aging effect of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250°C (482°F). MNGP does not have any Class 1 piping or fittings fabricated from CASS; the Class 1 reactor recirculation pump casings and covers are the only Class 1 components fabricated from CASS that are potentially susceptible to thermal aging embrittlement.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, and percent ferrite. Ferrite content will be calculated by using the Hull's equivalent factors (described in NUREG/CR-4513, Revision 1 (Reference 1.6.35)). Components with the potential for significant thermal aging embrittlement will be managed through qualified visual inspections, such as enhanced visual examination (EVT-1) or qualified UT methodology in accordance with ASME Code, Section XI.

Inspections are not required for components for which thermal aging embrittlement is not significant. In addition, screening for ASME Code Class 1 CASS valve bodies for significance of thermal aging embrittlement is not required, because the existing ASME Section XI inspection requirements performed as part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (B.2.3.1) are adequate for managing the aging effects of Class 1 valve bodies. Reactor vessel internal components fabricated from CASS are not within the scope of this AMP and are managed by the BWR Vessel Internals program (B.2.3.7).

Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program inspections, if required, will be based on ASME Code, Section XI, Table IWB-2500, and performed during each 10-year ISI interval. The MNGP ASME Section XI program plans direct any needed inspection schedules and the extent of the inspections in the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program planning documents as required to provide timely detection of flaws. Non-mandatory Appendix C to the 2019 ASME Code, Section XI, provides flaw evaluation procedures for CASS with ferrite content ≥ 20 percent. Those procedures may be used for flaw evaluations or flaw tolerance evaluations in this program until Appendix C to the 2019 Edition of ASME Code, Section XI is incorporated by reference in 10 CFR 50.55a. Once it is incorporated by reference in 10 CFR 50.55a, the evaluation procedures, as incorporated by reference in 10 CFR 50.55a, may be used in this program. This program may also use the flaw evaluation or flaw tolerance evaluation methods in the NRC-approved code cases that are documented in the latest revision of RG 1.147 (Reference 1.6.36).

Abnormal or unacceptable results identified are entered into the CAP for evaluation and resolution. Repairs and replacements are performed in accordance with the ASME Section XI Code, which specify the requirements in IWA-4000, per the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP (B.2.3.1).

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP will be a condition monitoring program whose methods will effectively detect and monitor the applicable aging effects and the frequency will be adequate to prevent significant age-related degradation.

This new program will be implemented prior to the SPEO.

NUREG-2191 Consistency

The MNGP Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M12, *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* as modified by SLR-ISG-2021-02-MECHANICAL.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

Review of the last two LRA/SLRAs submitted with a discussion of CASS recirculation pump casings related to thermal aging embrittlement identified the following:

- Peach Bottom Atomic Power Station SLRA: Inspections performed in 1993, 2002, 2003, and 2007 on all four recirculation pumps found no recordable indications.
- River Bend Station LRA: The Thermal Aging Embrittlement of CASS program is not credited at RBS and not applicable per NUREG-1801. There is no relevant OE related to thermal aging embrittlement in River Bend's LRA.

This review of thermal aging embrittlement concerns at BWRs shows no industry-wide issue regarding recirculation pumps.

- In 2014, during the Fort Calhoun Unit 1 71003 – Post-Approval Site Inspection for License Renewal, the staff noted that the licensee inappropriately ruled out stress corrosion cracking effects in the flaw tolerance evaluation performed for the RCS cast austenitic stainless steel piping based on the effectiveness of the Water Chemistry Program AMP (i.e., concluding that stress corrosion cracking was not a credible aging effect requiring management). The team determined that the LRA and SER described that the licensee credited the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP for managing crack initiation and growth due to stress corrosion cracking and loss of fracture toughness due to thermal aging embrittlement. The MNGP staff reviewed the IR and determined it not to be applicable to MNGP for initial LR.

<u>Plant-Specific Operating Experience</u>

- ARs from the past 10 years were reviewed and no instances of issues with the in-scope pump casings or covers were identified, nor any ISI inspections that require inspection of the internals of the pumps when disassembled per B12.20, B-L-2 “Pump Casings."

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.9 Flow-Accelerated Corrosion

The MNGP Flow-Accelerated Corrosion (FAC) AMP is an existing AMP that manages wall thinning caused by FAC, as well as wall thinning due to erosion mechanisms. This AMP is based on commitments made in response to NRC GL 89-08, *Erosion/Corrosion Induced Pipe Wall Thinning* (Reference 1.6.37) and relies on implementation of the EPRI guidelines in the Nuclear Safety Analysis Center, NSAC 202L-R4 (Reference 1.6.38) for an effective Flow-Accelerated Corrosion AMP.

This AMP includes the following:

(a) Identifying all FAC susceptible piping systems and components;

(b) Developing FAC predictive models to reflect component geometries, materials, and operating parameters;

(c) Performing analyses of FAC models and, with consideration of OE, selecting a sample of components for inspections;

(d) Inspecting components;

(e) Evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and

(f) Incorporating inspection data to refine FAC models.

The MNGP Flow-Accelerated Corrosion AMP monitors the effects of wall thinning due to FAC and erosion mechanisms by measuring wall thicknesses. Relevant changes in system operating parameters, (e.g., temperature, flow rate, water chemistry, operating time), which result from off normal or reduced power operations, are considered for their effects on the predictive analytical software CHECWORKS™, and these parameters are included in updates to the software. Opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation. Components are suitable for continued service if calculations determine that the predicted wall thickness at the next scheduled inspection (after next operating cycle) will meet the minimum allowable wall thickness. The minimum allowable wall thickness is the thickness needed to satisfy the component design loads under the original code of construction; additional code requirements are met, as applicable. A conservative safety factor is applied to the predicted wear rate determination to account for uncertainties in the wear rate calculations and UT measurements as recommended by NSAC-202L-R4.

The MNGP Flow-Accelerated Corrosion AMP procedures require reevaluation, repair, or replacement of components for which the acceptance criteria are not satisfied, prior to their return to service. For FAC, long term corrective actions may include replacing components with FAC resistant materials. Operating parameters that affect predicted FAC wear rates (e.g., operating time, hydrodynamic conditions, water treatment, component material, etc.) may also be adjusted, as long as the corresponding predictive analytical software (i.e., CHECWORKS™) models are also updated.

The MNGP Flow-Accelerated Corrosion AMP also manages wall thinning caused by erosion mechanisms in limited situations where periodic monitoring is used in lieu of eliminating the cause, typically a design or operational condition, in components that contain treated water or steam. These limited situations will be based on plant-specific OE and will be monitored similar to other FAC locations that are not modeled.

The MNGP Flow-Accelerated Corrosion AMP is a condition monitoring AMP. With that noted, the rate of FAC or erosion, where applicable, is affected by piping material, geometry and hydrodynamic conditions, and operating conditions such as temperature, pH, steam quality, operating hours, and dissolved oxygen content. Corrective action is taken in response to conditions identified from the results of the Flow-Accelerated Corrosion AMP inspections. These actions are driven by the CAP.

NUREG-2191 Consistency

The MNGP Flow-Accelerated Corrosion AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.M17, *Flow-Accelerated Corrosion*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Flow-Accelerated Corrosion AMP will be enhanced as follows for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program; and 4. Detection of Aging Effects	Reassess piping systems excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L-R4) to ensure the exclusion remains valid and applicable for operation beyond 60 years. If actual wall thickness information is not available for use in this re-assessment, a representative sampling approach will be used. This re-assessment may result in additional inspections.
5. Monitoring and Trending	Revise or provide procedure(s) to evaluate inspection results to determine if assumptions in the extent-of-condition review remain valid. If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities should consider the number or duration of these occurrences.

Operating Experience

A review of plant OE indicates the Flow-Accelerated Corrosion AMP is robust and that numerous work orders (WOs), CRs/ARs have been issued as a result of or to evaluate evidence of flow-accelerating corrosion.

Plant-Specific Operating Experience

- In April 2013, reducers that were being replaced downstream of certain valves showed signs of flow-accelerated corrosion. Piping was replaced with FAC resistant materials and the reducers were replaced with stainless steel effectively eliminating the effects of FAC. The replacements also restored the piping to the original thickness.

- In April 2014, during the focused area self-assessment of the FAC AMP, replacement piping materials not susceptible to FAC were not being used to manage FAC. When piping is replaced, use of a pipe material with a chrome content greater than 1.25 percent would be beneficial. Replacing piping with non-susceptible material has advantages as the systems or portions of systems constructed of stainless-steel piping, or low-alloy steel piping with nominal chromium contest equal to or great than 1.25 percent (high Chromium content) are generally not applicable to the FAC AMP as discussed in the FAC AMP procedure. Piping materials, classification, and standards for MNGP were revised to include chrome-moly piping.

- In April 2019, pipe wall thinning caused by FAC/erosion was verified during planned examinations. The wall thickness in the thinnest area was thinner than the acceptable minimum wall thickness for the location. Per the implementing document for the MNGP FAC AMP, the degraded area was documented, and stainless steel was used for the repair.

- In April 2021, wall thinning caused by FAC was detected during planned examinations. The code minimum wall thickness for the location was greater than the thinnest area detected during the examinations. The remaining service life of the pipe was determined 3.5 years, and per the MNGP FAC AMP, the damaged area was documented in the CAP and notification to plan for the replacement of the pipe section with FAC-resistant materials during the subsequent outage was submitted.

Program Assessments and Evaluations:

- A select AMP effectiveness review was completed in March 2015 to verify the commitments, inspections, and relevant activities were scheduled and performed in accordance with the program. No relevant findings were identified related to the MNGP FAC AMP.

- A self-assessment was completed in September 2019 in preparation for the LR Phase IV NRC inspection. No relevant findings were identified related to the MNGP FAC AMP.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020. The existing MNGP FAC AMP was enhanced to clarify loss of material on internal pressure boundary, FAC definition as pressure boundary wall thinning, overview of a representative sample, and references to an AR or AR to CAP or CAP.

The MNGP FAC AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Flow-Accelerated Corrosion AMP provides reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.10 Bolting Integrity

The MNGP Bolting Integrity AMP is an existing AMP that manages cracking, loss of preload, and loss of material for closure bolting for pressure-retaining components using preventive and inspection activities. This AMP also will manage submerged pressure-retaining bolting and closure bolting for piping systems that contain air or gas for which leakage is difficult to detect.

Applicable industry standards and guidance documents relevant to this AMP include NUREG-1339 (Reference ML031430208), *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, EPRI NP-5769 (Reference 1.6.39), *Degradation and Failure of Bolting in Nuclear Power Plants*, EPRI Report 1015336 (Reference 1.6.40), *Nuclear Maintenance Application Center: Bolted Joint Fundamentals*, and EPRI Report 1015337 (Reference 1.6.41), *Nuclear Maintenance Applications Center: Assembling Gasketed, Flanged Bolted Joints*.

The preventive actions associated with this AMP will include proper selection of bolting material; the use of appropriate lubricants and sealants in accordance with the guidelines of EPRI Report 1015336 and EPRI Report 1015337, along with additional recommendations from NUREG-1339; consideration of actual yield strength when procuring bolting material (e.g., ensuring any replacement or new pressure-retaining bolting has an actual yield strength of less than 150 ksi); lubricant selection (e.g., not allowing the use of molybdenum disulfide or other lubricants containing sulfur); proper torquing of bolts, checking for uniformity of the gasket compression after assembly; and application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, and/or engineering evaluation. These actions will preclude cracking, loss of preload, and loss of material.

The MNGP Bolting Integrity AMP provides visual inspection of pressure-retaining bolting per strategic engineering walkdowns. For closure bolting within the scope of the ASME Code, these inspections are supplemented by examinations performed under the MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD AMP (B.2.3.1). Inspections will be performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Closure bolting for HVAC Systems is managed by the MNGP External Surfaces Monitoring of Mechanical Components AMP (B.2.3.23).

For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspections (at least once per refueling cycle) ensure timely identification of indications of cracking, loss of preload (leakage), and loss of material. Visual inspection methods will be effective in detecting the applicable aging effects, and the frequency of inspection will be adequate to ensure that actions are taken to prevent significant age-related degradation. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the CAP.

Submerged closure bolting or bolting in piping systems containing air or gas for which leakage is difficult to detect will be inspected visually during maintenance activities that make the bolt heads accessible and bolt threads visible (such as disassembly). If opportunistic maintenance activities do not provide adequate access to 20 percent of the population (defined as the same material and environment combination) up to a maximum of 25 bolt heads and threads over each 10-year period of the SPEO, then integrity of bolted joints will be evaluated on a case-by-case basis using alternative means. For submerged closure bolting, methods for detecting leakage include (but are not limited to) periodic pump vibration measurements or operator walkdowns performed to demonstrate proper sump pump performance. For closure bolting on piping systems containing air or gas, methods for detecting leakage include the following:

- Visual inspection for discoloration when leakage of the environment inside the piping systems would discolor the external surfaces;
- Monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary;
- Soap bubble testing;
- Thermography testing when the temperature of the fluid is higher than ambient conditions; or
- Torque checks on components that are not normally pressurized (performed to ensure that bolting is not loose).

Bolting material with an actual yield strength greater than or equal to 150 ksi is not used for pressure-retaining bolting.

Indications of aging in pressure-retaining bolting for ASME Code Class 1, 2, and 3 components will be evaluated in accordance with Section XI of the ASME Code. Non-ASME Code inspections will follow acceptance criteria established in plant procedures and specifications. Leaking joints are not acceptable; bolted connections are required to show proper alignment, thread engagement, and no missing, degraded, loose or worn fasteners or components.

NUREG-2191 Consistency

The MNGP Bolting Integrity AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M18, *Bolting Integrity*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Bolting Integrity AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions 7. Corrective Actions	Replace obsolete references to NP-5067 and EPRI TR-104213 with reference to EPRI Reports 1015336 and 1015337 in procedures, standards, guidelines, and instructions addressing bolting. Integrate recommendations for bolt replacement and incorporate the guidance for materials selection and use of lubricants and sealants as appropriate.
2. Preventive Actions	Revise procedures to clarify that in addition to MoS_2, other lubricants containing sulfur will be prohibited from use on pressure-retaining closure bolting.
2. Preventive Actions 3. Parameters Monitored or Inspected	Revise procedure(s) to ensure that the maximum yield strength of newly procured pressure-retaining bolting material will be limited to an actual yield strength less than 150 ksi.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Create a new procedure to perform alternative means of testing and inspection for closure bolting where leakage is difficult to detect (e.g., piping systems that are submerged or that contain air or gas). The acceptance criteria for the alternative means of testing will be no indication of leakage from the bolted connections. Inspections will be performed to ensure that a representative sample of the population (defined as the same material and environment combination) of bolt heads and threads is accessed over each 10-year period of the SPEO. The representative sample will be 20% of the population (up to a maximum of 25 items).
4. Detection of Aging Effects	Update procedure(s) to ensure that bolted joints 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 provide reasonable assurance the components' intended functions are maintained.
4. Detection of Aging Effects	Revise procedure(s) to indicate that closure bolting greater than 2 in. in diameter (regardless of code classification) with actual yield strength greater than or equal to 150 ksi and closure bolting for which yield strength is unknown will require volumetric examination in accordance to that of

Element Affected	Enhancement
	ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 (i.e., acceptance standards, extent, and frequency of examination).
5. Monitoring and Trending	Update procedure(s) and include in the new inspection procedure requirements to project, where practical, identified degradation until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. Adverse results will be evaluated to determine if an increased sample size or inspection frequency is required.
7. Corrective Actions	Update procedure(s) and include the guidance for corrective action in the new inspection procedure (i.e., sample expansion and additional inspections if inspection results do not meet acceptance criteria) as described in NUREG-2191, Chapter XI.M18, Element 7.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. For example:

- Degradation of threaded bolting and fasteners in closures for the RCPB has occurred from boric acid corrosion, SCC, and fatigue loading. Assessment of NRC GL 91-17 resulted in additional process controls on high-strength bolting procurements at MNGP, including the requirement for an engineering evaluation of the bolt application and possible impact of SCC. Bolting integrity programs developed and implemented in accordance with docketed licensee responses to NRC communications on bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI Reports NP-5769, 1015336, and 1015337 and represent industry consensus.

- Degradation related failures have occurred in downcomer tee-quencher bolting in BWRs designed with drywells. The report presented in ADAMS

Accession No. ML050730347 describes discovery of failed high-strength alloy steel bolts. Evaluation of this OE determined that tensile and yield strength values for materials specified as acceptable for use in similar applications at MNGP are at least 40 percent less than those for the material in the failed bolts. The evaluation concluded that high-strength bolts are not installed anywhere within the wetted environment of the torus at MNGP; consequently, similar bolt failures are not considered likely, and no further action was recommended.

- SCC of A-286 stainless steel closure bolting has occurred when seal cap enclosures have been installed to mitigate gasket leakage at valve body-to-bonnet joints (NRC IN 2012-15). The enclosures surrounding the bolts filled with hot reactor coolant that had leaked from the joint and mixed with the oxygen-containing atmosphere trapped within the enclosure. The enclosures did not allow for inspections of the bolted joints. Evaluation of this OE determined that the subject material is a precipitation-hardened, austenitic stainless steel alloy designed for use at high temperatures where high tensile strength, excellent creep strength, and good corrosion resistance is required. There are no known applications where this type of high-temperature/high-pressure bolting would be used at MNGP; a search for this type of bolting identified no stock items in the plant inventory. Since the industry OE was specific to bolting that uses A-286 stainless steel, no further action was required at MNGP.

- In January 2015, the NRC issued RIS 2015-01 to inform the industry about enforcement discretion related to discrepancies between NDE qualification methods used by EPRI's performance demonstration initiative and those required by the ASME Code. Review of this notification confirmed that the issue had been previously identified by EPRI and evaluated for MNGP. Recommended resolutions were incorporated into the applicable examination procedure to ensure appropriate inspector qualification.

- Industry OE described an event in August 2019 where an ESW pump failed in-service testing acceptance criteria. Discovery of additional degradation resulted in the pump being inoperable. Direct cause of the failure was flange separation resulting in a loss of differential pressure; this failure was attributed to corrosion of carbon steel bolting submerged in a raw water environment accelerated by galvanic interactions with silt, stainless steel lock washers, and copper in the bolt thread lubricant. Evaluation of this OE verified that thread sealant used for carbon steel fasteners in raw water applications at MNGP does not contain copper.

These examples provide objective evidence that industry OE is being reviewed and evaluated to confirm that aging effects are adequately managed.

Plant-Specific Operating Experience

Action Request Examples

- In July 2012, inspection of newly installed "A" Reactor Water Cleanup (RWCU) pump noted corrosion on the end of a number of pump casing bolts.

Previous replacement of the casing gasket was unsuccessful in repairing leakage observed during hydrostatic testing. Following disassembly, inspection, and reassembly under the direction and guidance of a vendor service representative, an identical new pump (the “B” RWCU pump, which had not yet been installed) failed bench testing in August 2012 and was shipped to the vendor for further inspection and failure analysis. The vendor determined that the size of the existing gasket was inadequate based on their design practices. A new gasket was identified in September 2012 and installed in the “B” RWCU pump. The redesign was validated with no visible leakage observed during hydrostatic testing. Based on the lessons learned with the “B” RWCU pump, the existing gasket for the “A” RWCU pump was replaced with a new gasket provided by the vendor in October 2012. Studs and nuts were cleaned (or replaced if corroded) and torqued per vendor specification. The “A” RWCU pump was tested satisfactorily by pressure in-service-leak check and returned to service.

- During an extent of condition walkdown in April 2013, 15 of 16 studs on an RHR pump discharge valve were verified to be greater than hand-tight; however, one stud was found finger-tight (with full thread engagement) and could be turned by hand. There were no visible signs of leakage at the body-to-bonnet joint. After verifying adequate thread engagement, all bonnet fasteners for the valve were tightened per guidance in the plant bolting practices procedure. No leakage was noted during the follow-up inspection, nor was leakage noted during the subsequent RHR System leakage check. An operability assessment concluded that the valve would have been able to perform its design function.

- On reassembly following routine inspection and maintenance for an EDG in April 2015, lack of full thread engagement was reported for eight bolts securing a heat exchanger end bell. Review by the assigned system engineer confirmed that the same issue had been addressed in 2003 and resolved by removal of washers from the bolts; however, the applicable procedures and design records had not been appropriately updated. Washers were removed and adequate thread engagement verified; all fasteners for the end bell were tightened per guidance in the plant bolting practices procedure. The bolting configuration was documented via an ASME Section XI Repair/Replacement Plan approved in May 2015; plant drawings were updated in February 2017 to clarify ASME Code classification for the subject jacket water coolers. Clarifying notes were added to the applicable maintenance procedures in July 2015.

- During a system walkdown in June 2017, a small oil leak was reported coming from a four-bolt flange connection at the main bearing pressure lubricating oil pump for one of the EDGs. This condition did not impact system operability; the leak was classified as inactive in accordance with the leak management process. In July 2018, all four fasteners were tightened per guidance in the plant bolting practices procedure. No leakage was observed with the engine running upon return to service.

The above examples demonstrate that application of the MNGP Bolting Integrity AMP is effective in evaluating degraded conditions and implementing activities to maintain component intended function.

Program Assessments and Evaluations

Integrated Inspection reports issued over the last six years (2015 to 2021) were reviewed for NRC findings applicable to Bolting Integrity at MNGP. No findings considered NCVs related to the MNGP Bolting Integrity AMP were identified by the NRC or self-identified by MNGP during this period.

A focused self-assessment was conducted in February 2010 to evaluate the readiness of the MNGP license renewal implementation project for an impending NRC post-approval inspection. The focused self-assessment included reviews of AMP basis documents, testing and inspections, and implementing procedures. Updates to the AMP basis document were found necessary to satisfy record keeping requirements for walkdowns. Corrective actions to resolve this issue were implemented under the CAP.

The NRC Post-Approval site inspection described in License Renewal Phase II Inspection Report for MNGP was reviewed regarding the MNGP Bolting integrity AMP. The inspectors reviewed the licensing basis, program basis document, implementing procedures, and related ARs. The inspectors also interviewed plant personnel responsible for the program. The inspectors concluded that related commitments (to include industry guidance in associated AMPs), license conditions, and regulatory requirements were being met by the Bolting Integrity AMP.

A snapshot self-assessment of MNGP implementation for AMPs and commitments was conducted in May 2012. The assessment covered broad areas of management team oversight and was based primarily on interviews with assigned AMP owners. No related areas for improvement were noted; however, ownership of the Bolting Integrity AMP was reassigned to design engineering and an engineering work instruction was adopted.

A focused self-assessment was conducted in September 2019 in preparation for the License Renewal Phase IV NRC inspection. The focused self-assessment included review of AMP basis documents, an evaluation of changes against the requirements of 10 CFR 54.37(b), and documentation of training for AMP owners. Along with the need to assign program owners and schedule periodic self-assessments for AMPs, the report identified an editorial omission in the basis document for the Bolting Integrity AMP. Relationships between the Bolting Integrity AMP and other AMPs were clarified in the pertinent fleet procedure. Corrective actions to resolve all items related to the Bolting Integrity AMP were completed as part of license renewal implementation.

The NRC Post-Approval site inspection described in License Renewal Phase IV Inspection Report for MNGP was reviewed regarding the MNGP Bolting Integrity AMP. The NRC inspectors selected six AMPs (including the Bolting Integrity AMP) for evaluation considering risk insights and programs that were enhanced or new under the renewed operating license. As a result of observations during the inspection, thread lubricant controls were clarified in the Bolting Integrity AMP basis document to align with implementing procedures. No findings were identified in the report.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020 and some findings were identified related to the MNGP Bolting Integrity AMP. The review determined administrative actions to evaluate recent industry OE and to update references to the AMP in implementing procedures. The findings were resolved via the CAP.

The MNGP Bolting Integrity is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Bolting Integrity AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended functions of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.11 Open-Cycle Cooling Water System

The MNGP Open-Cycle Cooling Water System AMP is an existing AMP that manages aging effects caused by exposure of internal surfaces of piping, piping components, strainer elements, valve bodies, orifices, pump casings ESW, hoses (carbon steel and stainless steel), and heat exchanger components to an environment of raw, untreated (e.g., service) water that remove heat from SR SSCs during the SPEO. The following heat exchangers have components managed by the MNGP Open-Cycle Cooling Water System AMP: RHR heat exchangers, RHR pump motor/oil coolers, EDG jacket water heat exchangers, EFT condensers, RHRSW pump motor/oil coolers, core spray pump motor/oil coolers, and HPCI/RHR/CS room air cooling units.

The MNGP Open-Cycle Cooling Water System AMP relies, in part, on implementing the response to NRC GL 89-13, *Service Water System Problems Affecting Safety-Related Equipment* (Reference 1.6.42) and subsequent commitment changes to ensure that the effects of aging on the raw water Service Water Systems will be managed through the SPEO. NRC GL 89-13 defines an open-cycle cooling water system as a system or systems that transfer heat from SR SSCs to the ultimate heat sink. This AMP manages aging effects through surveillance and control to significantly reduce the incidence of flow blockage problems as a result of biofouling, as well as routine inspection and maintenance, so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of SR SSCs serviced by the raw water systems, which include components within the following systems:

- EFT System
- HTV System
- CSP System
- RHR System
- ESW Systems
- SSW System
- DGN System

The MNGP Open-Cycle Cooing Water System AMP applies to components constructed of various materials including steel (e.g., carbon steel, low alloy steel, and gray cast iron), stainless steel (SS), and copper alloys (including copper alloys with 15 percent zinc or less and copper alloys with greater than 15 percent zinc). MNGP does not have any components constructed of aluminum, nickel alloy, titanium, fiberglass, polymeric materials, and/or concrete exposed to a raw water environment that service SR SSCs. Therefore, management of these materials is not applicable to the MNGP Open-Cycle Cooling Water System AMP. For the components within the scope of the MNGP Open-Cycle Cooling Water Systems AMP that have internal coatings (e.g., various piping components within the ESW System, etc.), the internal coatings will be managed by the MNGP Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (B.2.3.28).

This AMP 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 specific heat exchangers, (c) routine inspection and maintenance so that corrosion, erosion, protective coating failure, fouling, and biofouling cannot degrade the performance of SR SSCs serviced by the raw water systems. Inspection methods primarily include visual inspection and ECT, but also include UT as needed.

The MNGP Open-Cycle Cooling Water System AMP utilizes control and preventive measures that include biocide injection, scale inhibitor, silt dispersant injection, and system flushing. The chlorination system regularly injects oxidizing biocide (e.g., sodium hypochlorite with bromide as needed) and/or nonoxidizing biocide, as needed, to control microbiologically-influenced corrosion (MIC) and macroscopic biofouling from species, such as Asiatic clams, zebra mussels, bryozoans, barnacles, etc. The raw water treatment also includes the use of scale inhibitor and silt dispersant injection as needed. Periodic flushing of infrequently used cooling loops is used to remove accumulations of biofouling agents, corrosion products, debris, and silt.

The AMP monitors for the aging effects of loss of material, wall thinning, reduction of heat transfer, flow blockage (due to biological and silt fouling), and cracking where applicable in system piping, heat exchangers, and other components exposed to raw water. The parameters monitored, inspected, or tested vary depending on the component and are based on OE. The AMP inspects internal surfaces of components (using visual and/or radiography techniques) of components exposed to raw water for presence of fouling and monitors the heat transfer performance of heat exchangers affected by fouling from the raw water systems. The RHR heat exchangers and EDG jacket coolers are performance tested annually. All SR Service Water Systems have flow monitoring permanently installed so that they may be tested.

Inspection scope, methods, and frequencies are in accordance with the MNGP GL 89-13 Program. The GL 89-13 Program states that testing frequencies can be adjusted to provide assurance that equipment will perform the intended function between test intervals, however, the minimum testing frequency is at least once every five years.

The MNGP Open-Cycle Cooling Water System AMP performs visual inspections to identify fouling and provide a qualitative assessment for loss of material due to various forms of corrosion and erosion. Although not required by GL 89-13, ECT is regularly performed for heat exchanger tubes to verify tube integrity and quantify the extent of wall thinning or loss of material. UT is performed to measure the internal and external surface condition and quantify the extent of wall thinning or loss of material based on the evaluation of the examination results and as documented in accordance with the CAP. Radiography is also used to identify and quantify pipe blockages due to fouling. Inspection and test results are used to determine corrosion rates, the extent of the biofouling or wall thinning, and corrective actions as needed. Inspections within the scope of the ASME Code are consistent with the respective ASME Code. Inspector qualifications are defined by the respective procedures and program documents and inspections and tests are performed by personnel qualified in accordance with those documents.

For heat exchangers that are tested for heat transfer capability (i.e., the RHR heat exchangers and EDG jacket coolers), heat removal capability is required to be within design values, and test results are trended by the system or program engineers. For heat exchangers that are routinely cleaned and inspected for degradation in lieu of testing (i.e. RHR pump motor/oil coolers, CSP pump motor/oil coolers, RHRSW pump motor/oil coolers, RHR room coolers, and CRV-EFT heat exchangers/condensers), inspection results are trended. Evidence of pipe blockage is evaluated to assess system operability and structural integrity of the piping system to maintain plant operability and reliability. Evidence of wall thinning (due to corrosion or erosion) is evaluated for its potential impact on the integrity of the piping system.

The acceptance criteria associated with the MNGP Open-Cycle Cooling Water System AMP are specified in the procedures that control the inspections and testing of components and acceptance criteria are established for the assigned activity, such as cleanliness, chemical treatment, erosion limits, and performance characteristics. Nondestructive examination (NDE) inspection techniques contain acceptance criteria and are used to determine the adequacy of the piping or heat exchangers. Acceptance criteria are based on maintaining the systems free of significant sediment build-up or macrofouling of marine growth and able to perform its intended functions. The MNGP GL 89-13 Program contains details of applicable performance and flow testing. Biofouling and particulate fouling in the raw water exposed heat exchangers and coolers is undesirable.

When wall thickness is measured, the measured thickness is not allowed to be less than the construction code required minimum wall thickness, otherwise corrective action is required. Where pipe wall thinning is identified, the projected wall thicknesses for the next scheduled inspection must be greater than the components' minimum wall thickness requirements, otherwise corrective action must be performed. For remaining service life projections, an administrative "critical thickness" greater than the minimum allowed thickness is determined. The remaining service life is conservatively calculated using a safety factor (SF) of 1.5 if the measured thickness is greater than the critical thickness and minimum allowed thickness. For additional conservatism, the remaining service life is calculated using an SF of 2.0 if the measured thickness is greater than the minimum allowed thickness but less than or equal to the critical thickness. For locations that do not have baseline exam data, the wear rate is calculated using the difference between the nominal thickness and the measured thickness. As additional conservatism, the actual corrosion rate for specific applications (including those components with no previous wall thickness measurements) may be augmented and updated by trending available inspection results from systems that have known similar degradation mechanisms based on service experience, in-plant tests, and/or laboratory experiments. If used, the augmented wear rate is greater than the calculated wear rates but does not exceed 0.100 inches per year. In lieu of any usable wear data, when the identified or suspected degradation mechanism is MIC, a wear rate of 0.100 inches per year is used. This is based on the upper bound limit of 0.100 inches per year for MIC from the EPRI 1010059 *Service Water Piping Guideline* (Reference 1.6.43).

With respect to heat exchanger visual inspections and ECT surveillance, tubes that do not meet or are projected to not meet minimum wall thickness acceptance criteria are manually plugged. Based on the respective heat exchanger's plugging limit and past plugging and trending, the heat exchanger's remaining life is projected. Corrective action must be performed prior to reaching the plugging limit. The MNGP

Open-Cycle Cooling Water System AMP includes reevaluation, repair, or replacement of components that do not meet minimum wall thickness requirements or exceed heat exchanger tube plugging limits.

The MNGP Open-Cycle Cooling Water System AMP compares component inspection results to the perceived relative risk ranking of the line/grouping from the asset management plan, which is also applicable for piping components with ongoing degradation mechanisms (e.g., MIC). If the as found condition was unexpected (more degraded than anticipated), then the susceptibility portion of the risk ranking for lines or groupings with similar operating conditions is re-evaluated, which can result in additional future planned inspections for that line or grouping.

NUREG-2191 Consistency

The MNGP Open-Cycle Cooling Water System AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M20, *Open-Cycle Cooling Water System*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Open-Cycle Cooling Water System AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Update the GL 89-13 Program procedure and related piping inspection procedures to monitor for internal cracking.
4. Detection of Aging Effects	Ensure Non-ASME Code tests and inspections follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.
5. Monitoring and Trending	Clarify in the heat exchanger testing and inspection procedures that inspection results are trended to evaluate the adequacy of surveillance frequencies so that proper function is maintained between surveillances.

Element Affected	Enhancement
5. Monitoring and Trending	Ensure the primary program procedures and relevant inspection procedures prompt an evaluation of the heat transfer capability of the SR, raw water supplied heat exchangers when fouling is identified.
5. Monitoring and Trending	Ensure the primary program procedures and relevant inspection procedures include trending of wall thickness measurements at locations susceptible to ongoing degradation due to specific aging mechanisms (e.g., MIC). The MNGP Open-Cycle Cooling Water System AMP owner will adjust the monitoring frequency and number of inspection locations based on the trending.
7. Corrective Actions	Update the primary program procedures and relevant inspection testing procedures to clarify that if fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, loss of material, and chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC) or recurring loss of material due to internal corrosion, the frequency and extent of wall thickness inspections will be increased commensurate with the significance of the degradation. If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement 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 relevant primary program procedure will also be updated to state that the number of inspections will be increased in accordance with the MNGP CAP; however, no fewer than 5 additional inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less.

Operating Experience

<u>Industry Operating Experience</u>

MNGP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions. The list below provides aging mechanisms and industry OE relevant to the MNGP Open-Cycle Cooling Water System AMP, as described in NUREG-2191, Section XI.M20:

- Loss of material due to corrosion (including MIC and erosion): IN 85-30, IN 2007-06, LER 247/2001-006, LER 306/2004-001, LER 483/2005-002, LER 331/2006-003, LER 255/2007-002, LER 454/2007-002, LER 254/2011-001, LER 255/2013-001, LER 286/2014-002

- Protective coating failure leading to unanticipated corrosion: IN 85-24, IN 2007-06, LER 286/2002-001, LER 286/2011-003

- Reduction of heat transfer and flow blockage due to fouling within piping and heat exchangers due to protective coating failures and accumulations of silt/sediment: IN 81-21, IN 86-96, IN 2004-07, IN 2006-17, IN 2007-28, IN 2008-11, LER 413/1999-010, LER 305/2000-007, LER 266/2002-003, LER 413/2003-004, LER 263/2007-004, LER 321/2010-002, LER 457/2011-001, LER 457/2011-002, LER 397/2013-002

- Cracking due to stress corrosion in brass tubing: LER 305/2002-002

- Pitting in stainless steel: LER 247/2013-004

- Industry OE (INPO IER L3-20-3) identified a December 2019 industry event where the Service Water System at a plant was declared inoperable due to flow blockage caused by at least 15 feet of river sediment covering the service water pipe outfall.

<u>Plant-Specific Operating Experience</u>

Between 2010 and 2021, several ARs were initiated to evaluate and/or correct degradation associated with SR SSCs exposed to raw water from the open-cycle cooling water systems (e.g., service water).

Only ARs with clearly identified and relevant aging effect(s) are listed below. MNGP is unique in that the monitoring and mitigation of aging effects is accomplished through this AMP and several implementing procedures addressing specific component types and degradation mechanisms. The following CAP items are grouped accordingly.

Service Water / Microbiologically Influence Corrosion Program:

Note: Not all ARs that document pitting are listed, particularly if wall thickness remained above the minimum thickness required by the ASME Code.

The service water radiation monitor piping system issues listed below provide a good demonstration of the site commitment to manage the effects of aging due general and localized corrosion. The effort to identify, quantify and locate damaged areas of this piping led to unique and preemptive piping replacements to ensure the design basis of the system was met and restored to original condition.

- In January 2013, The SW/MIC program required 3 locations to be UT tested as a result of a leak that was detected. The UT examinations were performed on 3 pipe sections located in the SSW radiation monitoring sampling station located on the torus catwalk. Two pipe sections upstream of an isolation valve had readings below the corrosion allowance of ASME B31.1 but above the minimum wall thickness. The low readings detected were characteristic of pitting, possibly due to MIC, as they were contained in localized areas, however there was also general thinning of the entire pipe wall. The leaking piping was replaced. The thinning piping upstream of the isolation valve was modified to encapsulate the portion of the damaged piping and install MIC resistant piping (AL6XN) to the first isolation valve by hot-tapping the 24-inch discharge header. Additionally, a work order replaced the 2-inch piping between the isolation valves for the Radiation Monitor System due to the identical conditions of water and system operation parameters.

- In January 2013, an unisolable section of 2-inch piping attached to the service water radiation monitor discharge header was found to be thinned by MIC pitting. Thickness readings revealed that the piping was just slightly above the calculated minimum wall thickness. The UT thickness examination was repeated in January 2015 and showed a continued decline in thickness, but still above minimum wall thickness. This thinning was resolved by the engineering change and work order that welded encapsulations and replaced portions of the damaged piping.

- In August 2016, localized pitting was detected on the unisolable portion of the service water radiation monitor. This pitting has been monitored periodically. The wall thickness at the most severe pit was just slightly above the minimum allowable wall thickness. An engineering change and work order encapsulated the affected area of corrosion.

The ESW and Filtration Service Water (FSW) System issues listed below provide a good demonstration of the site commitment to manage the effects of aging due general and localized corrosion. The effort to identify, quantify and locate damaged areas of this piping led to unique and preemptive piping replacements to ensure the design basis of the system was met and restored to original condition. The large-scale piping replacements noted below are a testament of the MNGP site commitment to manage the effects of aging mechanisms and maintain the current design basis of the plant.

- In March 2013, during SW-MIC examinations, a straight section of Division 1 FSW piping within the INS, was discovered with a wall thickness of 0.099 inches, which was below the minimum allowable thickness of 0.116 inches. As a corrective action, in April 2013, a work order replaced the thinning piping with like-for-like piping.

- In March 2017, localized pitting and wall thinning was identified on the inspected division 1 ESW System piping. Although the wall thickness was above the minimum required thickness, some locations were projected to decrease below the minimum thickness (ASME B31.1 Code), and therefore, work orders to replace such sections of degraded piping were scheduled.

Multiple ARs were placed into an adverse condition monitoring plan and thicknesses were monitored until the piping was replaced under a work order. In November 2021, the division 1 FSW piping replacement project replaced the remainder of the division 1 FSW piping from the intake tunnel to the EFB that had not been replaced during the EPU outage in 2013.

- In March 2017, a localized pit, possibly due to MIC, was detected on a 3-inch ESW line during the planned SW-MIC examinations. The inspection location line was on the turbine building catwalk. The respective corrective action evaluation documented that although the pit was below the administrative limit (T_{crit}) for thinning, the ASME B.31.1 Code compliance was maintained. As a proactive corrective action, pipe replacement was scheduled.

- In March 2017, a localized pit was detected during planned SW-MIC examinations. The inspection location was on a 3-inch ESW line in the EFB. The pit detected challenged the ASME B31.1 minimum wall thickness. The vendor who prepared this calculation was contacted concerning this localized pit. The vendor recalculated the minimum allowable thickness and determined that this piping remained capable of performing its design function and fully qualified to meet the ASME B31.1 code requirement. The piping was replaced under a work request and work order April 2017.

- In January 2019, localized pitting was detected during planned SW-MIC examinations in two locations on a 3-inch ESW line. The first location in the north end of the intake tunnel had a single pit with a thickness greater than the acceptable ASME B31.1 minimum wall thickness. The second location was above the east hallway from access control, which had multiple pits in the examination area, with the thinnest also measuring a thickness greater than the acceptable ASME B31.1 minimum wall thickness. The associated AR documented that although the pit was below the administrative limit (T_{crit}) for thinning, the ASME B.31.1 Code compliance was maintained. The respective piping was replaced as part of the division 1 FSW piping replacement project.

- In April 2019, a leak occurred in an elbow due to MIC pitting. A condition evaluation was performed and found that this elbow had been replaced only 8 years earlier (2011), again, due to a leak caused by MIC pitting. This particular section of pipe receives no bleach or biocide treatment. The evaluation recommended that this section of piping be fully examined for MIC pitting during the next divisional window. In April 2019, a work order replaced the leaking elbow and some downstream piping. NDE examinations performed in January 2021 identified one localized pit that was below the administrative limit (T_{crit}). The rate of degradation does not indicate reaching minimum wall thickness prior to the next scheduled inspection. This indication is being tracked by the SW/MIC program.

- In February 2013, a localized pit was detected during planned SW-MIC examinations. The inspection location was on an 18-inch RHRSW line in the torus room. The wall thickness in the thinnest area of the pit was just above the acceptable ASME B31.1 minimum wall thickness. The pit location was inspected again in 2017 and during the 4 years, the pit depth had not significantly changed and was still above the ASME B31.1 minimum wall thickness. The rate of degradation does not indicate reaching minimum wall thickness prior to the next scheduled inspection. This indication is being tracked by the SW/MIC program.

Heat Exchanger Program:

Not all ARs related to manual tube plugging after ECT were listed, particularly if the heat exchanger/cooler was well below the plugging limit and wear was not abnormal. Likewise, not all ARs that document pitting are listed, particularly if wall thickness remained above the minimum thickness required by the ASME Code.

- In October 2020, as part of an RHR heat exchanger inspection, several areas of the heat exchanger wall and divider plate were identified with ½-inch to 2-inch tubercules. The coating area under and immediately surrounding these tubercles was degraded and would easily flake away. No wall loss was observed, so pressure boundary function was not challenged. Mating surfaces were in good condition and no degradation was observed in these areas. The areas of degradation were remediated under a coating repair contingency work order.

- Modifications

  The RHRSW piping was replaced due to extensive MIC. The cause of MIC was due to poor initial biocide treatment of the system with chemical treatment and operating practices.

- Program Health Reports

  - The MNGP GL 89-13 Program Health Report published in January 2020 was reviewed. The program was graded as “White” due to a “White” score under the “Owner Proficiency” category. All other categories were graded as “Green,” including categories for program equipment evaluations, heat exchanger tube plugging margin, and abnormal heat exchanger examination, testing, results, conditions, or reoccurring equipment problems. The most recent NRC ultimate heat sink inspection was completed in March 2019 with no findings or violations. The site plan to achieve a “Green” score consists of the program owner continuing to obtain more experience managing the program.

  - The MNGP Service Water / MIC Program Health Report published in January 2021 was reviewed. The program was graded as “Green.” All categories were graded as “Green,” including categories for SR leaks, NSR leaks, components in service based on Code Case N513 evaluation, and components in-service utilizing temporary Code repair methods. At the time of the health report publication, no leaks had occurred on the in-scope raw water systems within the previous 12 months.

- Self-Assessments

  The self-assessment performed in February 2010, determined that with respect to the Open-Cycle Cooling Water System AMP, not all of the generic commitments were incorporated into the implementing procedures. Specifically, the fleet documents were missing the requirement to initiate a corrective action process (CAP) if a degraded aging management condition was identified. A “snap shot” self-assessment performed in 2016 identified the MNGP Open-Cycle Cooling Water System AMP as one of the AMPs that was properly incorporating OE, specifically, management of mechanical erosion degradation had been added to the AMP basis document. The self-assessment performed from December 2019 to March 2020 evaluated the MNGP Open-Cycle Cooling Water System AMP and determined that all of the elements were being satisfactorily implemented except for Element 9, which required editorial enhancements to the AMP basis document. A corrective action was implemented to address the AMP basis document editorial changes.

The raw water systems at MNGP have experienced loss of material due to MIC due to inadequate chemical treatment during much of the original license period. However, adequate chemical treatment processes are now in place, degraded sections have been replaced, and susceptible locations are being proactively replaced. These actions provide reasonable assurance that component failure due to MIC will not occur during the SPEO.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and one finding identified related to the MNGP Open-Cycle Cooling Water System AMP. As mentioned earlier, the effectiveness review determined that the AMP basis document required editorial enhancements to be made for alignment with Element 9.

The MNGP Open-Cycle Cooling Water System AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B

Conclusion

The MNGP Open-Cycle Cooling Water System AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended functions of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.12 Closed Treated Water Systems

The MNGP Closed Treated Water Systems AMP, previously known as the Closed-Cycle Cooling Water AMP, is an existing AMP that manages aging of the internal surfaces of piping, piping components, piping elements, and heat exchanger components exposed to a closed treated water environment during the SPEO. The AMP manages the aging effects of loss of material, cracking, and reduction in heat transfer. The program scope includes managing aging of the RBC System, EDG coolant system, and the HTV cooling system.

The MNGP Closed Treated Water Systems AMP is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. The AMP includes: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water to minimize corrosion and ensure the function of the equipment is maintained; (b) chemical testing of the water to demonstrate that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. The EDG coolant system is treated with a nitrite-based program, the RBC System is treated with a chromate-based program, and the HTV Cooling System is treated with a sulfite-based program.

To prevent loss of material and cracking, the MNGP Closed Treated Water System AMP periodically monitors the closed cooling system chemistry to verify it is being maintained within specified limits. The parameters monitored and the acceptable range of values are in accordance with EPRI Closed Cooling Water Guidelines and manufacturer recommendations where applicable.

When water chemistry concentrations are not within normal operating ranges, monitoring frequency is increased, as appropriate, and water chemistry parameters are returned to the normal operating range within the prescribed timeframe for each action level, or corrective actions are initiated through the CAP to evaluate and correct the water chemistry. The water sampling procedures provide corrective steps to take if water chemistry is outside of the recommended ranges. Results of samples analyzed are evaluated for potential adverse trends. Long-term chemistry trends for control and diagnostic parameters are reviewed on a periodic basis, including a review of the adequacy of control parameters and of chemicals added to the system to maintain chemistry control.

In addition to monitoring and maintaining the water chemistry parameters of the closed treated water systems, the MNGP Closed Treated Water Systems AMP includes condition monitoring activities, which provide for opportunistic and periodic inspections and nondestructive examinations on a representative sample of piping and components that is selected based on likelihood of corrosion or cracking. Opportunistic inspections will be performed whenever the system boundary is opened, and periodic inspections will be performed on a 10-year frequency.

NUREG-2191 Consistency

The MNGP Closed Treated Water Systems AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M21A, *Closed Treated Water Systems*, as modified by SLR-ISG-2021-02-MECHANICAL.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Closed Treated Water Systems AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program 2. Preventive Actions 3. Parameters Monitored or Inspected 5. Monitoring and Trending 6. Acceptance Criteria	Update implementing procedure(s) to include the Heating and Ventilation (HTV) Cooling System as a closed treated water system, subject to the same requirements as other closed treated water systems including: • Preventive actions, including the use of a corrosion inhibitor to maintain the function of the associated equipment and minimize the corrosivity of the water and the accumulation of corrosion products, • Parameters monitored in accordance with the EPRI Closed Cooling Water Guideline, • Normal operating ranges, limits, and frequencies for the parameters that are monitored, and • Acceptance criteria for the parameters that are monitored.
3. Parameters Monitored or Inspected	Update implementing procedure(s) or create new procedure(s) to include evaluation of the visual appearance of surfaces for evidence of loss of material. The results of surface or volumetric examinations will be evaluated for surface discontinuities indicative of cracking. The heat transfer capability of heat exchanger surfaces will be evaluated by either visual inspections to determine surface cleanliness, or functional testing to verify that design heat removal rates are maintained.

Element Affected	Enhancement
4. Detection of Aging Effects	Update implementing procedure(s) to include visual inspection of surfaces exposed to the closed treated water environment for evidence of loss of material, cracking, or fouling (of heat transfer surfaces) whenever the system boundary is opened. At a minimum, in each 10-year period during the SPEO, a representative sample (20 percent of the population, up to a maximum of 25 components) of piping and components will be inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The 20 percent minimum is surface area inspected unless the component is measured in linear feet, such as piping. In that case, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. The representative sample will be selected based on likelihood of corrosion or cracking. Inspections will be conducted in accordance with applicable ASME code requirements. If there are no ASME code requirements, inspections will be conducted in accordance with site procedures, which will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.
6. Acceptance Criteria	Update implementing procedure(s) or create new procedures(s) to include acceptance criteria for the results of visual inspection of surfaces exposed to the closed treated water environment. Any detectable loss of material, cracking, or fouling (of heat transfer surfaces) will be evaluated in the CAP.

Element Affected	Enhancement
7. Corrective Actions	Update implementing procedure(s) or create new procedure(s) to include corrective actions if the results of visual inspection of surfaces exposed to the closed treated water environment do not meet acceptance criteria. If fouling of heat transfer surfaces is identified, the overall effect will be evaluated for reduction of heat transfer, flow blockage, and loss of material. If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement 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 will be determined in accordance with the CAP; however, there will be no fewer than 5 additional inspections for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging affect 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 condition. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. The list below provides aging mechanisms and industry OE relevant to the MNGP Closed Treated Water Systems AMP, as described in NUREG-2191, Section XI.M21A:

- SCC of stainless steel reactor recirculation pump seal heat exchanger coils (attributed to localized boiling of the RBC System which concentrated water impurities on coil surfaces): LER 263/2014-001. This LER describes an event that occurred at MNGP that was first documented in August 2013 as an increase in radioactivity that was detected in the monthly sample of the RBC System that indicated a possible primary system leak into the RBC System. Monitoring and trending of plant parameters indicated that the system in-leakage had stopped. The station continued to monitor parameters on a weekly basis to identify any recurrence of the leak. In January 2014, the level in the RBC surge tank increased approximately one inch over a span of six hours after having been previously stable. An evaluation concluded that the leakage into the RBC System was from one of the recirculation pump seal coolers. The leakage was determined to be from the reactor pressure boundary, and a tech spec shutdown was required. The failure of the heat exchanger was due to a combination of factors: (1) the lack of a maintenance strategy in place to periodically check the condition of the heat exchanger or replace it, and (2) the engineering staff did not understand that, due to the operating conditions of the heat exchanger, there was potential for localized boiling, which increased the potential for intergranular stress corrosion cracking (IGSCC). The seal cooler was isolated, and all water flow was directed through the remaining seal cooler. A similar proactive modification was performed to the coolers on the opposite reactor recirculation pump.

As EPRI water chemistry guidelines are updated, MNGP updates the governing chemistry procedures to ensure the latest guidelines are being followed. This includes the latest recommendations for corrosion inhibitors.

Plant-Specific Operating Experience

In June 2013, the results of sampling indicated that the nitrite levels in the EDG coolant system were in the low end of the acceptable range of nitrite concentration. The corrosion inhibitor was determined to be performing its intended function and a protective oxide layer was forming on metal exposed during maintenance activities. A recommendation was made that the Chemistry department perform a chemical addition of corrosion inhibitor. CAP screening determined that no further actions were required, and the issue was resolved in the work management process. Subsequent sample results indicated that nitrite levels had returned to normal.

In March 2014, the monthly pre-run diesel coolant microbiological sample on the EDG coolant system indicated elevated levels of total viable count bacteria. No elevated populations existed in the other monitored bacteria groups. Other chemistry parameters that would indicate the presence of bacteria (nitrite, nitrate, pH, and NH3) were normal. The system was determined to be operable and performance of a resample was recommended. A further evaluation was performed in March 2015 and is discussed below.

In March 2015, a determination was made that the most likely cause of introduction of bacteria to the EDG coolant system was during immersion heater replacement. Best practices concluded that the coolant should not be re-filled with the same coolant that was removed for maintenance and that when the coolant system is breached for maintenance, it should be drained and refilled with new coolant. Maintenance procedures were updated to incorporate these changes.

In May 2015, an evaluation of sample results found that the EDG coolant chemistry was low out-of-spec for pH and high out-of-spec for chlorides. The deviation was evaluated and determined to be a result of a human performance error that resulted in the overdosing of the system with biocide, which in turn contributed to the elevation of chloride. There were no other indications of any increase in corrosion occurring.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no major findings were identified related to the MNGP Closed Treated Water Systems AMP. Minor findings were identified that required the AMP basis document references to be updated to the latest revision and implementing procedures to be updated to cite the closed cooling water aging management commitment. Procedure change requests were processed to complete the updates.

The MNGP Closed Treated Water Systems AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Closed Treated Water Systems AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is an existing AMP that manages aging effects associated with loss of material due to general corrosion and wear, deformed or cracked bridges, structural members, and structural components; and loss of material due to general corrosion, cracking, and loss of preload on bolted connections.

The MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of SLR. This AMP addresses the inspection and monitoring of crane-related SCs to provide reasonable assurance that the handling system does not affect the intended function of nearby SR equipment. Many crane systems and components are not within the scope of this AMP because they perform an intended function with moving parts or with a change in configuration, or they are subject to replacement based on qualified life.

The MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP includes periodic visual inspections to detect loss of material due to general corrosion and wear, deformed or cracked bridges, structural members, and structural components, and loss of material due to general corrosion, cracking, and loss of preload on bolted connections. NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants*, provides specific guidance on the control of overhead heavy load cranes. The activities to manage aging effects specified in this AMP utilize the guidance provided in ASME Safety Standard B30.2, *Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)* (Reference 1.6.44).

NUREG-2191 Consistency

The MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M23, *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Aging Management Program*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Update the MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP governing procedure and crane inspection procedures to state their respective visual inspection frequencies required by the 2005 version of ASME B30.2 or other appropriate standards of the ASME B30 series. A crane that is used in infrequent service, which has been idle for a period of one year or more, shall be inspected by a designated person and documented before being placed in service in accordance with the requirements listed in ASME B30.2 paragraph 2-2.1.3 (i.e., periodic inspection).
4. Detection of Aging Effects	Update the MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP governing procedure and inspection procedures to replace obsolete references to NP-5067 and EPRI TR-104213 with reference to EPRI Reports 1015336 and 1015337.
4. Detection of Aging Effects	Update the MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP governing procedure to state load handling system visual inspections are performed by personnel qualified in accordance with plant-specific procedures and processes.
4. Detection of Aging Effects	Update the MNGP Reactor Building crane bridge and trolley inspection procedures to inspect the trolley and bridge runway rail web and flange for damage or cracks.
5. Monitoring and Trending	Update the cattle chute lifting strongback inspection procedure to generate a CAP Action Request if any non-conforming conditions are found to perform evaluation with consideration for age related degradation.

Element Affected	Enhancement
6. Acceptance Criteria	Update the MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP governing procedure and inspection procedures to state that any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload for NUREG-0612 load handling systems is evaluated according to the 2005 version of ASME B30.2 or other applicable industry standard in the ASME B30 series.
7. Corrective Actions	Update the MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP governing procedure and inspection procedures to state that repairs made to NUREG-0612 load handling systems are performed as specified in the 2005 version of ASME B30.2 or other applicable industry standard in the ASME B30 series.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

There has been no history of corrosion-related degradation that threatened the ability of a crane to perform its intended function. Likewise, because cranes have not been operated beyond their design lifetimes, there have been no significant fatigue-related structural failures. OE indicates that loss of bolt preload has occurred, but not to the extent that it has threatened the ability of a crane structure to perform its intended function.

Plant-Specific Operating Experience

Metal shavings were found during preventive maintenance on the refueling platform trolley rail beam. Close examination of the metal shavings with a magnet indicated that the material was likely aluminum (i.e., non-magnetic) and caused by drilling versus component wear. A thorough inspection of the refueling platform was performed which also indicated that the metal shavings were not off of any components that would indicate a wear issue. A condition evaluation concluded that these metal shavings had been on the platform for quite some time and may have been off of scaffolding installed previously for past preventive maintenance work. All metal shavings were removed from the refueling platform and an inspection was completed to remove any other debris. No further action was required.

Two indentations were found on the steam dryer/separator strongback lifting device during preventive maintenance inspections in 2014. A condition evaluation concluded the indentations appeared to be legacy from fabrication or operation, not indicative of corrosion, wear, or fatigue. The indentions were found acceptable and did not impact fitness for service. A note regarding the indentations was added to the preventive maintenance procedure.

Minor bridge runway misalignment was found on the Reactor Building crane during preventive maintenance activities in 2014. This issue relates to the rail the bridge travels along, and the wheels that roll along it. This is minor misalignment that does not prevent the bridge from traversing its path but could result in long term excessive wear or degradation. Maintenance was performed in 2016 to check alignment and adjust, as necessary. The crane vendor provided a rail survey report documenting span, straightness, and rail to rail elevation being out of tolerance at multiple locations. No adjustments were made under this work order.

Bridge wheel and rail wear were found on the Reactor Building crane during preventive maintenance activities in 2015. A work order was created to monitor bridge wheel wear by taking measurements. The bridge and trolley wheels are active components and are not subject to aging management or SLR. This work order was closed to the 2016 alignment check work order discussed above.

As a follow up to the two preceding issues discussed above, a rail survey was performed in November 2016 and confirmed the runway rail span for the Reactor Building crane was out of alignment. The inspection report stated no excessive abnormal rail wear was noticed. The report also stated delaying of rail alignment will result in continual wear on the rail and wheels. Per vendor recommendation given the relatively little wear seen on the rail and wheels and the relatively little use of this crane on a yearly basis, the vendor indicated it may be more cost effective to replace the wheels that have flange wear that is approaching the minimum allowable thickness instead of attempting realignment. Since the crane is operating satisfactorily and there are no immediate safety issues, the vendor recommended that the owner closely monitor the runway rails and bridge wheels at least annually for any change in wear. If the flange wear approaches minimum allowable thickness, then the affected bridge wheels should be replaced. The bridge and trolley wheels are active components and are not subject to aging management for SLR. MNGP has chosen to monitor flange wear as opposed to completing a rail alignment. This is performed during the inspection of the crane.

During use of the Reactor Building crane in 2018 workers noted a scraping (Metal to metal) noise while the trolley was moving from north to south. The noise was noted with the hook loaded and unloaded. In addition, a potential small crack was found on the west side of the west trolley rail on the south side. During the inspection, additional damage was noted on the west rail. This damage does not impact the design or function of the trolley based on the margin within the calculation and minimal forces in the area because the damage was at the location of a rail clip. Also, the metal to metal noise noted, based on interview with mechanical maintenance, was when the trolley moved across the rail splices. Several actions were taken to address the noted crack:

- In order to remove the crack initiator (gap), shims were installed on either side of the crack to prevent further flexing of the rail at the crack location.
- All paint in the area of the crack and up to the top of the rail was removed to allow visual inspection of the crack propagation.
- NDE exams were performed after each loaded fuel cask move to confirm no change to the crack size. No abnormalities were found.
- Inspected the shim installed above after each loaded cask movement and verified that they were still intact, and no movement had occurred.
- Inspected both trolley and bridge runway rails. No new cracks or issues were found. All bolts and tie downs were tight with no additional findings. The previously identified crack did not appear to have grown.
- Installed rail clips on the north side of the crack and on both sides of the rail. This action strengthened the rail on either side of the crack.
- Updated Reactor Building crane 90 day inspection to include the trolley and bridge runway rail web and flange for damage or cracks.
- Determine long term repair of the rail. This condition was permanently repaired by cutting out the cracked section, shortening the existing rail and creating a new splice in accordance with the original design.

While performing non-destructive testing in 2018, using the dye penetrant method on the crane rail crack after lifting a loaded fuel cask, the results showed the bleed out from the crack increased in width and appeared the length of the bleed out had increased. Subsequent to this observation, the sealant that allowed the retention of the pool of penetrant was removed from the base of the rail. A substantial cleaning effort was made that included flushing of the indication and area beneath the indication. Subsequent dye penetrant exams showed that the indication appearance has returned to that of the original exam with no excessive bleed out.

The above examples demonstrate that application of the MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is effective in evaluating degraded conditions and implementing activities to maintain component intended function.

<u>Program Assessments and Evaluations</u>

A review of the Heavy Loads Program conducted by an outside vendor in 2016 concluded the site's implementation is consistent with the CLB. Their review made recommendations for additions that could be made to plant documentation to clarify conformance and better align with industry guidance.

The vendor report recommended reviewing the inspection currently being performed on the Dryer/Separator special lifting device socket pins with the original inspections recommended to meet ANSI N14.6 requirements. It was determined by MNGP the original inspection requirements state that only the accessible surfaces of the socket pins shall be examined by liquid dye penetrant NDE. This is acceptable and being met in the current inspection procedure.

The report also recommended that a technical justification be documented for the Dryer/Separator special lifting device socket pins with regards to the non-destructive evaluation (NDE) method. A technical justification was provided for use of either magnetic particle or liquid penetrant examinations as non-destructive evaluation methods for the Dryer/Separator special lifting device socket pin.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and one finding was identified related to the MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP. Findings were administrative in nature; general updates due to organizational and process changes were made in the AMP basis document.

The MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.14 Compressed Air Monitoring

The MNGP Compressed Air Monitoring AMP is an existing program which inspects, monitors, and tests the AIR System to provide reasonable assurance that the system will perform its intended function.

The MNGP Compressed Air Monitoring AMP includes preventive monitoring of water (moisture), and other contaminants to keep within specified limits. The MNGP Compressed Air Monitoring AMP will manage loss of material due to corrosion in components piping and piping components downstream of air dryers in compressed air systems.

The MNGP Compressed Air Monitoring AMP provides reasonable assurance that moisture is not collecting in compressed air systems or supplied components, and air quality is maintained so that loss of material is not occurring. Opportunistic visual internal inspections of Compressed Air System components will be performed in order to detect loss of material prior to a loss of intended function.

The MNGP Compressed Air Monitoring AMP relies on the guidance from the most current ANSI/ISA standards, and will rely on the guidance in ASME OM 2012, Division 2, Part 28 (Reference 1.6.45), and EPRI TR-108147 (Reference 1.6.46) for testing and monitoring air quality and moisture. Additionally, inspection and test results will be trended to provide for the timely detection of aging effects prior to loss of intended function.

NUREG-2191 Consistency

The MNGP Compressed Air Monitoring AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M24, *Compressed Air Monitoring*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Compressed Air Monitoring AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions 4. Detection of Aging Effects	Update the air quality sampling and/or governing procedure to incorporate the air quality provisions provided in the guidance of the EPRI TR 108147 and the related guidance in the ASME OM-2012, Division 2, Part 28.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Perform opportunistic visual inspections of accessible internal surfaces for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system. Acceptance criteria for visual inspection of internal surfaces will include no signs of corrosion (general, pitting, and crevice) that could indicate that the potential loss of function of the component, and the inspections and tests will be performed by qualified personnel.
4. Detection of Aging Effects 5. Monitoring and Trending	Update procedure(s) to trend the dew point temperature measurements.
5. Monitoring and Trending	Include monitoring and trending guidance from ASME OM-2012, Division 2, Part 28 as applicable.
7. Corrective Actions	Update procedure(s) to take appropriate corrective actions when corrosion is discovered on internal system surfaces.

Operating Experience

<u>Industry Operating Experience</u>

An OE search for Compressed Air Monitoring was performed over a 3-year period as part of a periodic AMP effectiveness review. New or revised industry standards, industry best practices related to the Compressed Air Monitoring AMP were reviewed, and IERs levels 1 to 4 listed on the INPO website from 2016 to 2019 were reviewed. No applicable OE was found related to the MNGP Compressed Air Monitoring AMP.

Plant-Specific Operating Experience

- In July 2020, an instrument and service dew point transmitter was reading 4.3°F while the operations round noted a maximum reading is -40°F. The -40°F is a trend band based on the normal system dew point for the system and is more conservative than the actual requirement of 0°F as documented in the MNGP Compressed Air Monitoring AMP implementing procedure. The dew point for this AR record ranged from 4.3°F to 10°F which were below the calculated dewpoint limit of 14°F per the industry guideline, ANSI/ISA S7.3. The intercooler drain and the aftercooler drain valves were refurbished to restore the dew point to the normal range. The finding and resolution were placed into the CAP.

- In September 2018, an instrument and service air dryer dewpoint was reading higher than the operations round maximum reading of -40°F, and it continued to trend at a higher level during the next shift round. The compressor was placed back into service after oil level was restored to normal. The compressor functioned as designed and dew point returned to the normal range. The finding and resolution were placed into the CAP.

  In June 2018, an instrument and service air dryer dewpoint transmitter was reading 24°F to 4°F while the operations round maximum reading was -40°F while the 15 instrument and service air compressor was operating properly and maintaining normal pressure. A WO was issued to monitor the air dryer dew point. The air compressor cooling unit coils were found to be plugged with debris. The coils were cleaned, and the dryer dew point was returned to the normal range. The finding and resolution were placed into the CAP.

Program Assessments and Evaluations:

- A select AMP effectiveness review was completed in March 2015 to verify the commitments, inspections, and relevant activities were scheduled and performed in accordance with the program. The MNGP Compressed Air Monitoring commitment to include inspection of air distribution piping based on the recommendations of EPRI TR-108147 was incorporated into the implementing procedure.

- A self-assessment was completed in September 2019 in preparation for the LR Phase IV NRC inspection, and no findings were identified related to the MNGP Compressed Air Monitoring AMP.

- AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no finding was identified related to the MNGP Compressed Air Monitoring AMP.

The MNGP Compressed Air Monitoring AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Compressed Air Monitoring AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.15 Fire Protection

The MNGP Fire Protection Program is an existing condition and performance monitoring program that manages the identified aging effects for fire barrier penetration seals, fire barriers, structural steel fire proofing materials, fire damper assemblies, fire rated doors and a halon fire suppression system installed in air/gas environments through the use of inspections/testing to detect aging prior to loss of intended function(s). The fire protection components' materials include carbon steel, cast iron, concrete (masonry) block, cementitious fireproofing (thermal insulation mastic), thermal fiber (silicate), fire stop sealant (silicone, silicone foam, caulk), galvanized steel, gray cast iron, reinforced concrete, rigid board (gypsum walls, etc.), and stainless steel.

The program is effective in detecting the applicable aging effects and as such includes a fire barrier visual inspection program, and a halon fire suppression system inspection. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barriers (e.g., walls, ceilings, and floors), fireproofing materials, fire damper assemblies, and periodic visual inspection and functional tests of associated fire rated doors to ensure that their functionality is maintained. The Fire Protection Program includes periodic visual inspection and testing of the Cable Spreading Room halon fire suppression system.

The program includes periodic visual inspection of twenty percent (20 percent) of penetration seals, including ten percent (10 percent) of each type in accordance with the approved MNGP fire protection program. Fire barrier penetrations seals are inspected for any sign of degradation such as cracking, seal separation from walls and components, separation of layers of material, rupture and puncture of seals that are directly cause by increased hardness and shrinkage of seal material due to aging.

Fire barriers are periodically inspected, in accordance with the approved MNGP fire protection program, to identify any abnormalities that have the potential to adversely affect the fire resistive capability, such as cracking, and loss of material. Fire damper assemblies are inspected for corrosion, cracking, and missing or loose parts.

The Cable Spreading Room halon fire suppression system requires a periodic system functional test, air flow test through headers and nozzles to assure no blockage, and a visual inspection of headers and nozzles. Visual inspection of the Cable Spreading Room halon fire suppression system is required to detect any signs of degradation, such as loss of material (due to corrosion and wear), cracking and mechanical damage.

NUREG-2191 Consistency

The MNGP Fire Protection AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M26, *Fire Protection*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Fire Protection AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Clarify the fire damper assemblies inspection procedure(s) inspect for corrosion and cracking on all in-scope fire damper assemblies.
5. Monitoring and Trending	Trend the inspection results for timely detection of aging effect so that appropriate corrective actions can be taken. Where practical, identified degradation is projected until the next scheduled inspection. For sampling-based inspections, evaluate the results against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. Require an assessment for additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation.
6. Acceptance Criteria	Update document to include "no signs of corrosion, cracking or degradation that could result in loss of fire protection capability due to loss of material" as acceptance criteria for fire damper assemblies. Update Fire Protection AMP documents to include "no separation of layers of material" and "no ruptures or punctures" as acceptance criteria for fire barrier penetration seals.

Element Affected	Enhancement
7. Corrective Actions	Revise FP AMP documents as appropriate: to indicate that, for fire barrier penetration seals, if degradation is detected within the inspection sample of penetration seals, that the scope of the inspection is expanded to include additional seals in accordance with MNGPs Fire Protection AMP. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's CAP.

Operating Experience

Industry Operating Experience

Silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes [NRC IN 88-56, IN 94-28, and IN 97-70]. Degradation of electrical raceway fire barrier such as small holes, cracking, and unfilled seals were found on routine walkdown (NRC IN 91-47 and NRC GL 92-08). Fire doors have experienced wear of the hinges and handles.

MNGP periodically evaluates industry OE items for applicability per the OE Program and takes appropriate actions. (Note: Consistent with initial LR, MNGP does not use Thermo-Lag fireproofing material)

Plant-Specific Operating Experience

The following OE provides objective evidence that the Fire Protection Program will be effective in ensuring that component intended functions are maintained consistent with the CLB through the SPEO.

- In February 2010, water leakage from a temperature CV was flowing through floor cracks onto fireproof material covering an I-Beam on the lower floor; the unit was out of service. This water saturated through this material and was dripping onto the floor. The issue was discussed with the fire protection engineer and the vendor of the material; both the fire protection engineer and vendor agree that the small section of material that had been wetted should have no impact on the ability of the material to protect the structure. As such, the fire protection insulation was determined to remain functional. The temperature CV was replaced. This item was entered into the CAP.
- In May 2015, during the performance of Fire Penetration Inspection, the five fire penetrations were found in a functional but degraded state. The penetrations had cracking that was more than minor in width and depth, however, no air flow was observed through the penetration seals. Based on the potential fire severity to which the penetrations may be subjected, the penetrations in their current state would have been able to limit fire propagation. The CRE remained capable of maintaining pressure boundary

such that the emergency filtration trains could supply filtered air during a high radiation event. The penetrations were repaired. This item was entered into the CAP.

- In June 2016, during the performance of the fire door inspections cracking was noted in the door skin of a fire door. Since the doors were not tested in a configuration that included the existence of cracking in the door skin, the door could not be verified to prevent the spread of a fire in the affected fire zone. Therefore, the fire door was declared non-functional; the fire door was replaced, restoring its functionality. This item was entered into the CAP.
- In June 2016, halon system performance was documented to be degrading between 2014 and 2016. This degraded performance had resulted in numerous unplanned fire impairment entries. Through troubleshooting activities leakage was identified at multiple Swagelok fittings on all 8 halon cylinders. Overall, Swagelok fittings are known to be extremely reliable for maintaining pressure with no leakage. However, the halon Swagelok fittings were subject to repetitive loosening and tightening which resulted in the failure of the threading to maintain a perfectly leak tight connection. This eventually caused the leakage that had been present over the past 2-year period. In addition, a leaking valve was discovered on T-3R cylinder; the cylinder was replaced to resolve this issue.

  The replacement of the fittings was completed (for the main and reserve bank of halon cylinders, respectively). The long term corrective action to prevent recurrence was replacement of the Swagelok fittings associated with the cylinders on a 5-year frequency. The scope of existing PMs was increased to include the periodic replacement of fittings for the halon cylinder banks. Additionally, during the weight checks performed every 6 months all disturbed fittings are checked for leakage. This item was entered into the CAP.

- In May 2017, during the performance of fire barrier penetration seal visual inspections a fire penetration was found non-conforming. The non-conformance observed was that the Flamemastic coating did not extend down the cables from the cable spreading room ceiling. The fire penetration was considered functional but non-conforming since the lack of extension of Flamemastic coating, in this case, would not prevent the penetration from stopping the spread of fire. The penetration's ability to maintain the CRE was not challenged by this condition, which was evidenced by the lack of airflow through the penetration. The fire penetration was repaired to meet its fire rated design requirement. In addition to the repairs being made to the fire barrier penetration, additional minor repairs were made to other penetration seals. This item was entered into the CAP.

The examples above demonstrate that identified findings are entered into the CAP and appropriate actions are taken for resolution.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020; one clarification was required related to the MNGP Fire Protection AMP:

In May 2020, while performing the AMP effectiveness review for fire protection, NUREG-1865, MNGP SER related to the License Renewal states fire penetration seals will be performed every 18 months and these inspections will cover ten percent (10 percent) of each type of seal. However, the Fire Protection Program performs penetration inspections every 24 months, and those inspections include twenty percent (20 percent) of all penetrations. This meant that the frequency stated in the SER had changed and the breakdown of ten percent (10 percent) of each seal type penetration seal was not being performed. As a result, the Fire Protection Program and Fire Barrier Penetration Seal Visual Inspection procedures were revised to align with the SER requirements. This is objective evidence that periodic AMP Effectiveness reviews are capable of identifying program findings during AMP implementation.

The MNGP Fire Protection AMP is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Fire Protection AMP, with enhancements, will provide reasonable assurance that the identified effects of aging will be adequately managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.16 Fire Water System

The MNGP Fire Water System AMP is an existing AMP, that manages the aging effects of loss of material, wall thinning, cracking, and flow blockage due to fouling for water-based fire protection system components. This objective is achieved through conducting periodic visual inspections, tests, and flushes performed in accordance with the 2011 Edition of the National Fire Protection Association Code, NFPA 25 (Reference 1.6.47).

MNGP Fire Water System AMP applies to water-based fire protection system components, including closed head sprinklers; open head sprinklers and spray nozzles; fittings; valve bodies; fire pump casings; metallic equipment hoses (not fire hoses); hydrants; hose stations; standpipes; diesel fire pump heat exchanger; and aboveground, buried, and underground piping and components that are tested in accordance with the NFPA codes and standards. Full-flow testing and visual inspections are conducted in order to provide reasonable assurance that loss of material, cracking, and flow blockage are adequately managed. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (a) normally dry but periodically are subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect, are subjected to augmented testing or inspections. Also, portions of the system (e.g., fire service main, standpipe) are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions are initiated.

The MNGP Buried and Underground Piping and Tanks AMP (B.2.3.27) is used to manage aging of the external surfaces of buried and underground fire water system piping. The MNGP Bolting Integrity AMP (B.2.3.10) will manage loss of preload, cracking, and loss of material for fire water system closure bolting. MNGP External Surfaces Monitoring of Mechanical Components AMP (B.2.3.23) will manage cracking of air-exposed copper alloy (>15 percent Zn) valve bodies, sprinklers, spray nozzles, and piping components through the SPEO. The MNGP Selective Leaching AMP (B.2.3.21) is used to manage aging of surfaces within the fire water system that have a material-environment combination susceptible to selective leaching.

Fast-response and traditional sprinkler heads are either replaced or tested in accordance with NFPA 25 prior to exceeding their 20-year or 50-year service life, respectively. In lieu of replacing sprinklers, an option exists to remove and test a representative sample of sprinklers from one or more sample areas at an off-site laboratory per the guidance of NFPA 25. If the sprinkler heads are not replaced, the required testing will be repeated at 10-year intervals. Several aging sprinkler heads have already been replaced per preventive maintenance activities.

Fire water systems are regularly flushed to remove blockage and obstructions such as corrosion products and sediment. The surveillance intervals associated with periodic flushing are listed below:

- Yard fire hydrants and fire water mains are periodically flushed and/or flow tested to remove sedimentation and fouling.

- Intervals for flushes/tests of closed head sprinkler systems and open head sprinklers and fixed spray nozzles (deluge systems) are performed at various intervals, depending on the system.

The MNGP Fire Water System AMP also utilizes biocide as a preventive measure to prevent MIC. As another preventive measure, many fire water components are provided with a protective external coating to minimize the potential for external degradation. Additionally, the main fire water header is internally coated with a cementitious lining. Coatings minimize corrosion by limiting exposure to the environment, however, coatings are not credited for eliminating the aging effects/mechanisms.

To address potential loss of material, cracking, and flow blockage, the MNGP Fire Water System AMP monitors several fire water system parameters. Periodic fire pump capacity testing is performed. Additionally, periodic fire water system flow testing and flushing is performed to provide reasonable assurance that the fire water system can maintain required system pressures, flow rates, and internal conditions (i.e., no fouling or sediment blockage). Occurrences of pipe/component leakage are also visually identified during these tests. Flushes and/or tests of closed head sprinkler system mains and open head sprinkler and spray nozzles are performed periodically. Some fire protection and/or service water piping sections are internally lined with cementitious coatings. Visual examinations of these coatings for indications of loss of material or cracking are not performed by the MNGP Fire Water System AMP, but rather those coatings are managed by the MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (B.2.3.28).

Water-based fire protection system components are subject to flow testing, other testing, and visual inspections. Testing and visual inspections will be performed per NUREG-2191, Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations,” with the following exception. An exception is taken that instead of performing the main drain tests on all standpipes and risers, the main drain tests will be performed on 20 percent of all standpipes and risers. With respect to aging effect detection, the MNGP Fire Water System AMP, requires the following tests/inspections:

- Flow tests that confirm the system is functional by verifying the capability of the system to deliver water to fire suppression systems at required pressures/flow rates. This includes the periodic fire main system flush and flow tests and the periodic fire pump capacity testing.

- Visual inspections on piping/components which identify external/internal surface corrosion and internal blockage, and;

- Visual inspections of yard fire hydrants and fire hydrant flow tests, as well as periodic indoor hose station flow blockage testing, to detect degradation.

Fire hydrant hose hydrostatic tests and gasket inspections are not required for SLR since these items are considered consumables that are regularly replaced per applicable codes, such as NFPA safety standards, technical specifications, or site approved programs.

Continuous fire water system pressure monitoring is performed, and low pressure alarms alert the operators to abnormal system conditions. Therefore, loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. Additionally, periodic functional testing, internal inspections, and wall thickness evaluations of selected portions of the system provide reasonable assurance that corrosion and fouling are not occurring to an extent that an intended function would be compromised.

The diesel driven fire pump and the two electric-driven fire water pumps are equipped with the suction screens/strainers; therefore, the screens/strainers will be inspected per NFPA 25, Section 8.3.3.7.

Since the MNGP has no fire water storage tanks, the respective inspection requirements per NFPA 25, Sections 9.2.5.5, 9.2.6, and 9.2.7 are not applicable. Likewise, MNGP does not utilize foam water sprinkler systems; therefore, the respective visual inspections and surveillances per NFPA 25, Sections 11.2.7.1 and 11.3.2.6 are not applicable.

Results from the various surveillances are evaluated per the respective procedures. Any degradation identified by visual/volumetric inspections or flushes/flow testing is reported, evaluated, and corrected through the MNGP CAP. Acceptance criteria for observed degradation, flow obstruction, discharge flow/pressures, or minimum wall thickness are defined in the MNGP Fire Water System AMP procedures used to perform the respective inspections and tests.

NUREG-2191 Consistency

The MNGP Fire Water System AMP, with enhancements, will be consistent with one exception to the 10 elements of NUREG-2191, Section XI.M27, *Fire Water System*.

Exception to NUREG-2191

NFPA 25, Section 13.2.5 specifies annual main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and CVs. Note 10 of Table XI.M27-1 of NUREG-2191 indicates that annual testing can be changed to an every refueling outage frequency if plant-specific OE shows that there is no loss of intended function for the SSC and aging effects managed by that test. However, as noted by the NRC, NFPA 25 was written for a broad range of facilities, including those conducting a few main drain tests at its standpipe locations and those with numerous standpipes (as is typical for nuclear power plants) (Reference ML18212A151). Managing this large quantity of water is not practical at MNGP because of the difficulty of water disposal with biocide and in the radiologically controlled area. For any location inside the radiologically controlled area, the water would have to be transported out of the building or possibly processed as radiological waste. The NRC also stated that conducting tests on 20 percent of a population is consistent with the extent of recommended tests in several sampling-based aging management programs (e.g., GALL Report AMP XI.M38, *Internal Surfaces in Miscellaneous Piping and Ducting Components*) (Reference ML18212A151). Plant-specific OE review indicates that a loss of function of the piping between the fire main loop and the deluge or alarm check valves associated with fire suppression systems at MNGP due to flow blockage has not occurred.

MNGP will take the following exception to the NUREG-2191 guidance in the MNGP Fire Water System AMP:

(1) MNGP will perform the main drain tests on 20 percent of the standpipes and risers every refueling cycle. This is an exception to NUREG-2191, Table XI.M27-1 and NFPA 25, Section 13.2.5.

Justification for Exception: Conducting tests on 20 percent of this population is consistent with the extent of recommended tests in several sampling-based aging management programs (e.g., GALL Report AMP XI.M38, *Internal Surfaces in Miscellaneous Piping and Ducting Components*). The number of main drain tests conducted every refueling cycle will be sufficient to establish a trend if potential flow blockage is occurring.

Enhancements

The MNGP Fire Water System AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO. This AMP is to be implemented and its pre-SPEO inspections and tests begin no earlier than 5 years prior to the SPEO. The pre-SPEO inspections and tests are to be completed no later than six months prior to entering the SPEO or no later than the last refueling outage prior to the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Clarify within the new internal pipe inspection procedure and relevant preventive maintenance activities that when visual inspections are used to detect loss of material, the inspection technique must be capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations are performed. The internal inspections will be performed during the periodic system and component surveillances.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Create new procedure(s) and/or preventive maintenance activities to perform volumetric wall thickness inspections on the portions of the water-based fire protection system components that are periodically subjected to flow but are normally dry as follows: In each 5-year interval of the SPEO, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping. If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.
4. Detection of Aging Effects	Update existing inspection/testing procedures and create new procedures to incorporate the surveillance requirements stated in NUREG-2191, Section XI.M27, Element 4 and Table XI.M27-1, which are based on NFPA 25, 2011 edition. This includes testing or replacement of fast-response and traditional sprinkler heads that have been in service for 20 or 50 years, respectively, in accordance with NFPA 25.

Element Affected	Enhancement
5. Monitoring and Trending	Update inspection and test procedures and preventive maintenance activities to state that, where practical, degradation identified will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. Results of flow testing (e.g., buried and underground piping, fire mains, and sprinklers/spray nozzles), flushes, and wall thickness measurements will be monitored and trended per the instructions of the specific test/inspection procedure. Degradation identified by flow testing, flushes, and inspections will be evaluated. If the condition of the piping/component does not meet acceptance criteria, then the issue will be entered into the MNGP CAP, and the component will be evaluated for cleaning, recoating, repair, or replacement. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation.
5. Monitoring and Trending	Update spray and sprinkler system flushing procedures to enable trending of data. Specifically, the existing flushing procedures and preventive maintenance activities will be revised to document and trend deposits (scale or foreign material). Incorporate acceptance criteria that no loose fouling products can exist in the systems that could cause flow blockage in the sprinklers or deluge nozzles. Existing flushing procedures, as well as new flushing procedures, will include steps to compare the amount of deposits to the previous inspections' results, and if the trend shows increasing deposits, then the MNGP CAP will be utilized to drive improvement.
6. Acceptance Criteria	Clarify within the new internal inspection procedure and relevant existing preventive maintenance activities which inspect wall thickness that identified wall loss greater than the manufacturer's tolerance will be entered into the MNGP CAP for engineering evaluation and trending to determine when minimum wall thickness will be reached and what corrective actions are required.

Element Affected	Enhancement
7. Corrective Actions	Update the respective pipe inspection procedures to state that if an obstruction inside piping or sprinklers is detected during pipe inspections, the material is removed, and the inspection results are entered into the MNGP CAP for further evaluation. An evaluation is conducted to determine if deposits need to be removed to determine if loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers is detected, a flush is conducted in accordance with the guidance in NFPA 25 Annex D.5, *Flushing Procedures*. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the MNGP CAP.
7. Corrective Actions	Update the existing flow test procedures and the existing deluge system and sprinkler system flush/test procedures to state that if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation, then additional tests will be conducted. The number of increased tests is determined in accordance with the MNGP CAP; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent-of-condition and extent-of-cause analysis will be conducted to determine the further extent of tests.

Element Affected	Enhancement
7. Corrective Actions	Clarify within the new internal inspection procedure(s) and relevant preventive maintenance activities that for ongoing degradation mechanisms such as MIC or recurring internal corrosion, the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation. The number of increased inspections is determined in accordance with the MNGP CAP; however, no fewer than five additional inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. The additional inspections will occur at least every 24 months until the rate of recurring internal corrosion occurrences no longer meets the criteria for "loss of material due to recurring internal corrosion" as defined in NUREG 2192. 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 reinspection interval. If a failure occurs (e.g., a through-wall leak or blockage impacting operability), the failure mechanism shall be identified and used to determine the most susceptible system locations for additional inspections, including consideration to the other unit systems as driven by the corrective action program. When piping is replaced prior to failure, due to concerns with wall thinning or blockage, inspections are considered for similar areas of the system to determine the presence and extent of degradation.

The following table provides additional detail on the enhancements based on NUREG-2191 Table XI.M27-1. Note: An asterisk (*) following the number or letter designating a paragraph indicates that explanatory material on the paragraph can be found in NFPA 25 Annex A.

Description	NFPA 25 Section	Required Enhancements
Sprinkler Systems		
Sprinkler inspections	5.2.1.1	The relevant sprinkler inspection procedures and/or maintenance plans (MPs) will be updated to be performed on a refueling outage interval (i.e., every 24 months), in accordance with the interval requirements of NUREG-2191 Table XI.M27-1 Note 10, but not necessarily during refueling outages. Note: The NFPA 25, Section 5.2.1.1 requirements apply to closed head sprinklers, NOT open head sprinklers or open head spray nozzles. To meet the interval requirements of NUREG-2191 Table XI.M27-1 Note 10, some of the relevant procedures will need to be updated to be performed on a refueling outage interval (i.e., 24 months). The relevant procedures and preventive maintenance activities will be enhanced to incorporate the requirements of NFPA 25 Section 5.2.1.1 to ensure that sprinklers are visually inspected from the floor level and meet the acceptance criteria, which include no signs of leakage, significant corrosion, foreign materials, paint (unless painted by manufacturer), physical damage, loading, and loss of fluid in glass bulb heat responsive elements. Additionally, sprinklers shall be installed in the correct orientation (e.g., upright, pendent, or sidewall). Any sprinkler that does not meet these criteria shall be replaced. 5.2.1.1* Sprinklers shall be inspected from the floor level [at least on a refueling outage interval (i.e., every 24 months) per NUREG-2191 Table XI.M27-1 Note 10.] 5.2.1.1.1* Sprinklers shall not show signs of leakage; shall be free of corrosion, foreign materials, paint, and physical damage; and shall be installed in the correct orientation (e.g., upright, pendent, or sidewall). 5.2.1.1.2 Any sprinkler that shows signs of any of the following shall be replaced: (1) Leakage

Description	NFPA 25 Section	Required Enhancements
		(2) Corrosion (3) Physical damage (4) Loss of fluid in the glass bulb heat responsive element (5)*Loading (6) Painting unless painted by the sprinkler manufacturer 5.2.1.1.3* Any sprinkler that has been installed in the incorrect orientation shall be replaced. 5.2.1.1.4 Any sprinkler shall be replaced that has signs of leakage; is painted, other than by the sprinkler manufacturer, corroded, damaged, or loaded; or is in the improper orientation. 5.2.1.1.5 Glass bulb sprinklers shall be replaced if the bulbs have emptied. 5.2.1.1.6* Sprinklers installed in concealed spaces such as above suspended ceilings shall not require inspection. 5.2.1.1.7 Sprinklers installed in areas that are inaccessible for safety considerations due to process operations shall be inspected during each scheduled shutdown.
Sprinkler testing	5.3.1	Fast-response and traditional sprinkler heads shall either be replaced or tested in accordance with NFPA 25 prior to exceeding their 20 year or 50 year service life, respectively. If the sprinkler heads are not replaced, the required testing will be repeated at 10 year intervals. Update relevant preventive maintenance activities to incorporate the following sprinkler testing instructions of NFPA 25, Section 5.3.1 subsections. The required steps and information are as follows: 5.3.1.1*: Where required by this section, sample sprinklers shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing.

Description	NFPA 25 Section	Required Enhancements
		5.3.1.1.1: Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be tested. 5.3.1.1.1.1: Test procedures shall be repeated at 10-year intervals. 5.3.1.1.1.2: [Not applicable since MNGP does not utilize sprinklers manufactured prior to 1920.] 5.3.1.1.1.3*: Sprinklers manufactured using fast-response elements that have been in service for 20 years shall be replaced, or representative samples shall be tested and then retested at 10-year intervals. 5.3.1.1.1.4*: Representative samples of solder-type sprinklers with a temperature classification of extra high [325°F (163°C)] or greater that are exposed to semi-continuous to continuous maximum allowable ambient temperature conditions shall be tested at 5-year intervals. 5.3.1.1.1.5: Where sprinklers have been in service for 75 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing and repeated at 5-year intervals. 5.3.1.1.1.6*: Dry sprinklers that have been in service for 10 years shall be replaced or representative samples shall be tested and then retested at 10-year intervals. 5.3.1.1.2*: Where sprinklers are subjected to harsh environments, including corrosive atmospheres and corrosive water supplies, on a 5-year basis, either sprinklers shall be replaced, or representative sprinkler samples shall be tested. 5.3.1.1.3: Where historical data indicate, longer intervals between testing shall be permitted.

Description	NFPA 25 Section	Required Enhancements
		5.3.1.2*: A representative sample of sprinklers for testing per NFPA 25, Section 5.3.1.1.1, shall consist of a minimum of not less than four sprinklers or 1 percent of the number of sprinklers per individual sprinkler sample, whichever is greater. 5.3.1.3: Where one sprinkler within a representative sample fails to meet the test requirement, all sprinklers within the area represented by that sample shall be replaced. 5.3.1.3.1: Manufacturers shall be permitted to make modifications to their own sprinklers in the field with listed devices that restore the original performance as intended by the listing, where acceptable to the authority having jurisdiction.
Standpipe and Hose Systems		
Flow tests	6.3.1	The relevant flow test procedure and preventive maintenance activity are performed on an interval which meets the 5-year interval requirement. The procedure and preventive maintenance activity will be enhanced to ensure the following requirements of NFPA 25, Section 6.3.1 and subsections are met: 6.3.1: Flow Tests. 6.3.1.1*: A flow test shall be conducted every 5 years at the hydraulically most remote hose connections of each zone of an automatic standpipe system to verify the water supply still provides the design pressure at the required flow. 6.3.1.2: Where a flow test of the hydraulically most remote outlet(s) is not practical, the authority having jurisdiction shall be consulted for the appropriate location for the test. 6.3.1.3: All systems shall be flow tested and pressure tested at the requirements for the design criteria in effect at the time of the installation. 6.3.1.3.1: The actual test method(s) and performance criteria shall be discussed in advance with the authority having jurisdiction.

Description	NFPA 25 Section	Required Enhancements
		6.3.1.4: Standpipes, sprinkler connections to standpipes, or hose stations equipped with pressure reducing valves or pressure regulating valves shall have these valves inspected, tested, and maintained in accordance with the requirements of NFPA 25, Chapter 13. 6.3.1.5: A main drain test shall be performed on all standpipe systems with automatic water supplies in accordance with the requirements of NFPA 25, Chapter 13. 6.3.1.5.1: The test shall be performed at the low point drain for each standpipe or the main drain test connection where the supply main enters the building (when provided). 6.3.1.5.2: [Not applicable per NUREG-2191 Table XI.M27-1 Note 9, which states that calibration of measuring and test equipment (i.e., pressure gauges provided for flow tests) can be conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.]
Private Fire Service Mains		
Underground and exposed piping flow tests	7.3.1	The relevant test procedures and preventive maintenance activities are performed on an interval which meets the 5-year interval requirement. The procedure and preventive maintenance activity will be enhanced to ensure the following requirements of NFPA 25, Section 7.3.1 and subsections are met: 7.3.1*: Underground and Exposed Piping Flow Tests. Underground and exposed piping shall be flow tested to determine the internal condition of the piping at minimum 5-year intervals. 7.3.1.1: Flow tests shall be made at flows representative of those expected during a fire, for the purpose of comparing the friction loss characteristics of the pipe with those expected for the particular type of pipe involved, with due consideration given to the age of the pipe and to the results of previous flow tests.

Description	NFPA 25 Section	Required Enhancements
		7.3.1.2: Any flow test results that indicate deterioration of available water flow and pressure shall be investigated to the complete satisfaction of the authority having jurisdiction to ensure that the required flow and pressure are available for fire protection. 7.3.1.3: Where underground piping supplies individual fire sprinkler, standpipe, water spray, or foam-water sprinkler systems and there are no means to conduct full flow tests, tests generating the maximum available flows shall be permitted. Where flushing through a hydrant occurs, also perform the hydrant barrel draining per NFPA 7.3.2. Per NUREG-2191 Table XI.M27-1 Note 9, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Hydrants	7.3.2	The relevant test procedure and preventive maintenance activities have fire hydrant flushing (flow check) performed on an interval which meets the refueling outage interval requirement of NUREG-2191, Table XI.M27-1, Note 10. This test ensures that the hydrants and their respective piping systems are functioning properly. This procedure and relevant preventive maintenance activity will be enhanced to clarify the other requirements of the NFPA 25, Section 7.3.2 subsections: 7.3.2.1: Each hydrant shall be opened fully and water flowed until all foreign material has cleared. 7.3.2.2: Flow shall be maintained for not less than 1 minute. 7.3.2.3: After operation, dry barrel and wall hydrants shall be observed for proper drainage from the barrel. 7.3.2.4: Full drainage shall take no longer than 60 minutes. 7.3.2.5: Where soil conditions or other factors are such that the hydrant barrel does not drain within 60 minutes, or where the groundwater level is above that of the hydrant drain, the hydrant drain shall be plugged and the water in the barrel shall be pumped out.

Description	**NFPA 25 Section**	**Required Enhancements**
		7.3.2.6: Dry barrel hydrants that are located in areas subject to freezing weather and that have plugged drains shall be identified clearly as needing pumping after operation. Per NUREG-2191 Table XI.M27-1 Note 9, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Fire Pumps		
Suction screens (strainers)	8.3.3.7	The fire pump suction baskets (screens/strainers) are also regularly inspected and cleared of debris or obstructions as part of the service water bay inspection and dredging procedures. The relevant flushing and flow/deluge test procedures are performed at various intervals which ensure that ensure that each pump is activated at least once every 24-month refueling outage, meeting the refueling outage interval requirement of NUREG-2191, Table XI.M27-1, Note 10. These procedures will be enhanced to ensure the following requirements of NFPA 25, Section 8.3.3.7 are met: 8.3.3.7* Suction Screens. After the waterflow portions of the annual [or refueling outage interval; i.e., 24-month] test or fire protection system activations, the suction screens [strainers] shall be inspected and cleared of any debris or obstructions.
Water Storage Tanks		
Exterior inspections	9.2.5.5	N/A
Interior inspections	9.2.6, 9.2.7	N/A

Description	NFPA 25 Section	Required Enhancements
Water Spray Fixed Systems		
Strainers (after each system actuation)	10.2.1.6, 10.2.1.7, 10.2.7	The relevant functional test procedure and preventive maintenance activities are (or will be) performed at least on a refueling outage interval (i.e., every 24 months), but not necessarily during refueling outages, which meets the interval requirements of NUREG-2191, Table XI.M27-1, Note 10. The relevant procedures and preventive maintenance activities will be enhanced to meet the inspection, flushing, and parts replacement and repair requirements of NFPA 25, Sections 10.2.1.7, 10.2.7, and associated subsections. These enhancements include flushing the mainline strainers until clear after each operation or flow test, inspecting and cleaning the strainers in accordance with the manufacturer's instructions, and replacing or repairing damaged or corroded parts. 10.2.1.6: Nozzle strainers shall be removed, inspected, and cleaned during the flushing procedure for the mainline strainer. 10.2.1.7: Mainline strainers shall be removed and inspected every 5 years for damaged and corroded parts. 10.2.7* Strainers. 10.2.7.1: Mainline strainers (basket or screen) shall be flushed until clear after each operation or flow test. 10.2.7.2: Individual water spray nozzle strainers shall be removed, cleaned, and inspected after each operation or flow test. 10.2.7.3: All strainers shall be inspected and cleaned in accordance with the manufacturer's instructions. 10.2.7.4: Damaged or corroded parts shall be replaced or repaired.
Operation test	10.3.4.3	Note: These requirements apply to open head sprinklers or open head spray nozzles, NOT closed head sprinklers.

Description	NFPA 25 Section	Required Enhancements
		The relevant functional test procedures are or will be performed at least every 3 years, which is in accordance with the interval requirements of NUREG-2191 Table XI.M27-1 Note 8. If testing results identify the potential for nozzle plugging impeding the discharge pattern, then tests will be conducted annually, except for protected components that are inaccessible because of safety considerations, such as those raised by continuous process operations, radiological dose, or energized electrical equipment are tested during each scheduled shutdown but not more often than every refueling outage interval. The relevant procedure and preventive maintenance activities test open head spray nozzles with water and meet the NFPA 25, Section 10.3.4.3.1 requirement by ensuring that spray patterns are not impeded by plugged nozzles, that nozzles are correctly positioned, and that obstructions do not prevent discharge patterns from wetting surfaces to be protected. Update the relevant procedures and preventive maintenance activities to clarify that if obstructions are found, the systems are retested after cleaning in accordance with NFPA 25, Section 10.3.4.3.2. 10.3.4.3* Discharge Patterns. 10.3.4.3.1* The water discharge patterns from all of the open spray nozzles shall be observed to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. 10.3.4.3.1.1 Where the nature of the protected property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with air to ensure that the nozzles are not obstructed. 10.3.4.3.2 Where obstructions occur, the piping and nozzles shall be cleaned and the system retested. The relevant procedures and preventive maintenance activities will be annotated to credit existing steps for the above NFPA requirements and enhanced to state that if loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no

Description	**NFPA 25 Section**	**Required Enhancements**
		deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met.
Foam Water Sprinkler Systems		
Strainers (after each actuation)	11.2.7.1	N/A
Operational Test Discharge Patterns (annually)	11.3.2.6	N/A
Storage tanks (internal – 10 years)	Visual inspection for internal corrosion	N/A
Valves and System-Wide Testing		
Main drain test	13.2.5	Relevant fire water system testing/flushing procedures and preventive maintenance activities will be revised to incorporate the following instructions and requirements for the fire main drain test from NFPA 25, Section 13.2.5 and subsections. These functional test procedures and preventive maintenance activities are or will be performed at least every 24 months (based on the refueling outage interval, but not necessarily during refueling outages), which meets the interval requirements of NUREG-2191, Table XI.M27-1, Note 10. The required steps and information are as follows: 13.2.5*: A main drain test shall be conducted [at least on a refueling outage interval (i.e., every 24 months)] at each water-based fire protection system riser to determine whether there has been a change in the condition of the

Description	NFPA 25 Section	Required Enhancements
		water supply piping and CVs and any time the CV is closed and reopened at system riser. As identified in the exception to the MNGP Fire Water System AMP, MNGP will perform the main drain tests on 20 percent of the standpipes and risers every refueling cycle. 13.2.5.1: In systems where the sole water supply is through a backflow preventer and/or pressure reducing valves, the main drain test of at least one system downstream of the device shall be conducted on a quarterly basis. 13.2.5.2: When there is a 10 percent reduction in full flow pressure when compared to the original acceptance test or previously performed tests, the cause of the reduction shall be identified and corrected if necessary. Per NUREG-2191 Table XI.M27-1, the following notes also apply: • Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are inspected during each scheduled shutdown but not more often than every refueling outage interval. • Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Obstruction Investigation		
Obstruction, Internal Inspection of Piping	14.2, 14.3	New procedure(s) will be prepared and implemented to incorporate the following instructions and requirements for internal inspection of piping and obstruction investigation from NFPA 25, Sections 14.2, 14.3, and subsections. Relevant preventive maintenance activities [maintenance plans] will also be updated accordingly. The required steps and information are as follows: 14.2: Internal Inspection of Piping. 14.2.1: Except as discussed in 14.2.1.1 and 14.2.1.4 below, an inspection of piping and branch line conditions shall be

Description	NFPA 25 Section	Required Enhancements
		conducted every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material. 14.2.1.1: Alternative nondestructive examination methods [that can ensure that flow blockage will not occur] shall be permitted. 14.2.1.2: Tubercules or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC). 14.2.1.3*: If the presence of sufficient foreign organic or inorganic material is found to obstruct pipe or sprinklers, an obstruction investigation shall be conducted as described in Section 14.3. 14.2.1.4: Non-metallic pipe shall not be required to be inspected internally. 14.2.1.5: 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. 14.2.1.6*: Inspection of a cross main is not required where the system does not have a means of inspection. 14.2.2*: In buildings having multiple wet pipe systems, every other system shall have an internal inspection of piping every 5 years as described in 14.2.1 above. 14.2.2.1: During the next inspection frequency required by 14.2.1 above, the alternate systems not inspected during the previous inspection shall have an internal inspection of piping as described in 14.2.1. 14.2.2.2: 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.

		14.3: Obstruction Investigation and Prevention. 14.3.1*: An obstruction investigation shall be conducted for system or yard main piping wherever any of the following conditions exist: (1) Defective intake for fire pumps taking suction from open bodies of water (2) The discharge of obstructive material during routine water tests (3) Foreign materials in fire pumps, in dry pipe valves, or in check valves (4)*Foreign material in water during drain tests or plugging of inspector's test connection(s) (5) Plugged sprinklers (6) Plugged piping in sprinkler systems dismantled during building alterations (7) Failure to flush yard piping or surrounding public mains following new installations or repairs (8) A record of broken public mains in the vicinity (9) Abnormally frequent false tripping of a dry pipe valve(s) (10) A system that is returned to service after an extended shutdown (greater than 1 year) (11) There is reason to believe that the sprinkler system contains sodium silicate or highly corrosive fluxes in copper systems (12) A system has been supplied with raw water via the fire department connection (13) Pinhole leaks (14) A 50 percent increase in the time it takes water to travel to the inspector's test connection from the time the valve trips during a full flow trip test of a dry pipe sprinkler system when compared to the original system acceptance test. 14.3.2*: Systems shall be examined for internal obstructions where conditions exist that could cause obstructed piping.

Description	**NFPA 25 Section**	**Required Enhancements**
		14.3.2.1: If the condition has not been corrected or the condition is one that could result in obstruction of the piping despite any previous flushing procedures that have been performed, the system shall be examined for internal obstructions every 5 years. 14.3.2.2: Internal examination shall be performed at the following four points: (1) System valve (2) Riser (3) Cross main (4) Branch line 14.3.2.3: Alternative nondestructive examination methods [that can ensure that flow blockage will not occur] shall be permitted. 14.3.3*: If an obstruction investigation indicates the presence of sufficient material to obstruct pipe or sprinklers, a complete flushing program shall be conducted by qualified personnel. [For obstruction investigation flushing procedures, refer to NFPA 25 Annex D.5.] If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met. Per NUREG-2191 Table XI.M27-1, the following notes also apply: • Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are inspected during each scheduled shutdown but not more often than every refueling outage interval.

Description	NFPA 25 Section	Required Enhancements
		• Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements. Additionally, the new procedure will specify that portions of water-based fire system components that have been wetted but are normally dry, such as dry pipe or preaction sprinkler system piping and valves, are subjected to augmented testing and inspections beyond those of NUREG-2191 Table XI.M27-1. The augmented tests and inspections are conducted on piping segments that cannot be drained or piping segments that allow water to collect: • In each 5-year interval, beginning 5 years prior to the SPEO, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. • In each 5-year interval of the SPEO, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping. • If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.
General		
General	N/A	Update all inspections and test procedures and preventive maintenance activities to clarify that inspections and tests shall be performed by personnel qualified to perform the task. The inspections and tests shall also include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes.

Description	NFPA 25 Section	Required Enhancements
		Update inspection and test procedures and preventive maintenance activities to state that, where practical, degradation identified will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. Results of flow testing (e.g., buried and underground piping, fire mains, and sprinklers/spray nozzles), flushes, and wall thickness measurements will be monitored and trended per the instructions of the specific test/inspection procedure. Degradation identified by flow testing, flushes, and inspections will be evaluated. If the condition of the piping/component does not meet acceptance criteria, then a condition report will be written per the MNGP CAP, and the component will be evaluated for cleaning, recoating, repair, or replacement. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation.
General	N/A	A new procedure will incorporate the methodology for extending fire protection surveillance frequencies consistent with EPRI Report 1006756 (Reference 1.6.48) and NRC guidance as follows: • The data collection guidelines in the procedure will follow the EPRI Report 1006756 guidelines. The number of years prior to the SPEO, from which data would be collected for modifying test and inspection frequencies, will be determined based on the current surveillance intervals under evaluation. Surveillances up to quarterly require 2 years of data, surveillances performed in the range of quarterly up to annually require 3 years of data, and surveillances performed in the range of annually up to fuel cycle require 5 years of data. • The data collection guidelines will include the bounding recommendations for sample size from EPRI Report 1006756. To modify test and inspection frequencies, a minimum sample size of 100 independent samples is recommended. This amount of data will ensure low uncertainty and avoid excessive failure sensitivity. A

Description	NFPA 25 Section	Required Enhancements
		sample size of 100 is a desired lower limit, but the analysis can be done with fewer points if a small number of components are involved. • The use of performance data to modify surveillance intervals is based on the current length of the surveillance interval. Performance data will not be used to modify surveillance intervals that are greater than two times the refueling interval.

Note: An asterisk (*) following the number or letter designating a paragraph indicates that explanatory material on the paragraph can be found in NFPA 25 Annex A.

Sprinkler heads are either being tested or replaced prior to the respective sprinkler systems reaching 50 years in age. Four sprinkler systems have already reached 50 years in service, and therefore, the respective sprinkler heads have been replaced.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the Operating Experience Program and takes appropriate corrective actions.

OE shows that water-based fire protection systems are subject to loss of material due to corrosion, MIC, or fouling; and flow blockages due to fouling. Loss of material has resulted in sprinkler system flow blockages, failed flow tests, and piping leaks. Inspections and testing performed in accordance with NFPA standards coupled with visual inspections are capable of detecting degradation prior to loss of intended function. The following OE was listed in NUREG-2191, Section XI.M27, as relevant to the PSL Fire Water System AMP:

- In October 2004, a fire main failed its periodic flow test which was attributed to fouling because of an accumulation of corrosion products on the interior of the pipe wall and tuberculation. Subsequent chemical cleaning to remove the corrosion products from the pipe wall revealed several leaks. Corrosion products removed during the chemical cleaning were observed to settle out in normally stagnant sections of the water-based fire protection system, resulting in flow blockages in small diameter piping and valve leak-by. (Reference ML12220A162, ML12306A332, and ML13029A244).

- In October 2010, a portion of a preaction spray system failed its functional flow test because of flow blockages. Two branch lines were found to have significant blockages. The blockage in one branch line was determined to be a buildup of corrosion products. A rag was found in the other branch line. (Reference ML13014A100).

- In March 2012, the staff and licensee personnel found that a portion of the internally galvanized piping of a 6-inch preaction sprinkler system could not be properly drained because the drainage points were located on a smaller diameter pipe that tied into the side of the 6-inch pipe. A boroscopic inspection of the lower portions of the pipe showed that it contained residual water, that the galvanizing had been removed, and that significant quantities of corrosion products were present whereas in the upper dry portions, the galvanized coating was still intact. Reference IN 2013-06 (Reference 1.6.49).

Plant-Specific Operating Experience

Between 2010 and 2021, several ARs were initiated to evaluate and/or correct degradation associated with SSCs exposed to raw water from the FIR System. Only ARs with clearly identified and relevant aging effect(s) were listed below.

- Intake Fire Sprinkler Flow Blockage: In August 2011, an intake fire protection preaction sprinkler system was unable to pass flow during functional testing. Subsequent visual inspections identified flow blockages in the inspector's test valve, the piping leading to the inspector's test valves, and three vertical risers. The flow blockages were determined to be a buildup of corrosion products. Additionally, in October 2011, the respective root cause evaluation did not systematically address how the MNGP Fire Water System AMP could have prevented the blockage from causing a sprinkler to be nonfunctional. There was no guidance on preparing apparent or root cause evaluations involving an aging issue to ensure the appropriate portions of the AMP are evaluated. Corrective actions included providing training on the root cause evaluation guidance procedures that were issued concurrently during the resolution of the INS sprinkler root cause analysis. This OE resulted in the issuance of License Event Report (LER) 2011-006, *Intake Structure Fire Suppression System Blockage* (Reference ML113050425). In June 2012, during the periodic evaluation for AMP effectiveness it was determined that the Fire Water System AMP activities were not being performed in a timely manner resulting in challenges to the intake fire water system. Corrective actions were initiated to address weaknesses in the performance of the AMP activities and the current condition of the AMP is determined to be effective. A root cause analysis of the flow blockage determined that the respective sprinkler piping had multiple locations that had not met the NFPA 13, Section 8.16.2.5 requirements for auxiliary drains. The code states that auxiliary drains shall be provided where a change in piping direction prevents drainage of system piping through the main drain valve. This issue was entered into the CAP and in March 2014, a modification to install auxiliary drains for the intake fire sprinkler piping was completed.

- In June 2012, during the performance of a work order, the diesel generator sprinkler system piping was determined to have an inadequate slope, making it nonconforming to NFPA code requirements. Sprinkler piping directly above the diesel generator was sloped in the opposite direction of a drain which could allow water to be held up in a preaction sprinkler system which should be dry when the system is not in use. The piping had been sloped this way since installation. After a flush, an internal inspection performed as an extent of condition did find minor loose silt; however, it was not substantial enough to cause blockage concerns and would have cleared through the sprinkler head if a fire were to have occurred. This finding was entered into the CAP and in September 2013, a work order corrected the slope of the sprinkler piping.

- In August 2012, during the performance of a work order, the radwaste sprinkler system piping was determined to have an inadequate slope making it nonconforming to NFPA code requirements and some sprinkler branch lines were not sloped back to the main header. Also, portions of the main header were not sloped in the direction of an adequate drain. This could allow for water to be held up in a preaction sprinkler system which should be dry when the system is not in use. The piping had been sloped this way since installation. During the inspection there was minimal silt found in the main and no blockage was found which could have caused flow concerns. An evaluation determined that the slope of the piping should be corrected and that the flush connections should be changed to a flush connection that would allow for drainage. This finding was entered into the CAP and a work order is scheduled to correct the pipe slope and replace the flush connections with draining flush connections in 2023.

- Intake Tunnel Leaks and Pitting:

    - In August 2013, two pinhole leaks (approximately 4 dpm each) were identified on the FIR System piping in the intake tunnel. This amount of leakage was evaluated as not preventing the FIR System from performing its function. The condition evaluation identified that the pipe had experienced wall loss due to general corrosion as well as localized pitting accelerated by MIC. The evaluation identified that the pipe was an optimal environment for MIC, due to low flow and minimal biocide treatment for the first 26 years of plant life. Immediate actions were initiated to perform UT pipe wall measurements in the affected areas. Additionally, a sample of 5 other locations were UT examined and pitting was identified on 4 out of those 5 locations. The condition assessment determined that additional biocide would likely not be effective since the microbe colonies were now protected by tubercules formed during corrosion. Pipe leak repairs were completed under an engineering change and work order. This finding was entered into the CAP and a proactive long-range plan was created to replace the respective thinning fire water system piping. The piping replacement was completed in March 2018.

    - In March 2015, a modification to patch two pinhole leaks on the 8-inch schedule 40 FIR System piping was completed. One leak was one a straight pipe and the other was on a 45° elbow. UT of the leak in the straight pipe section showed that the leak was caused by through-wall penetration of a bell-shaped pit in an area where local wall thinning had taken place. The wall thinning had reduced the wall thickness from the original 0.322 inches to 0.271 inches. This localized thinning was centered on the leak location. UT of the leak in the weld (elbow) showed that the leak was caused by through-wall penetration of a pit in an area where local wall thinning had taken place. Surface patches were fillet welded over the leak locations and adjacent thinning areas.

- In March 2017, three localized pits were detected during planned MIC examinations. After detecting localized pitting that challenged the ASME B31.1 minimum wall thickness, paint was removed from the areas to enhance the accuracy of the ultrasonic examination results and re-inspected. The inspection location was on a fire protection line, at the INS. The measured wall thicknesses of the pits located axially along this pipe were originally measured as 0.069, 0.129, and 0.118 inches and subsequently measured as 0.061 and 0.097 inches after paint removal. The calculated acceptable ASME B31.1 minimum wall thickness for the pipe was 0.067 inches. The pit measuring 0.061 inches was below the ASME B31.1 minimum wall thickness. Based on the UT characterization of the flaws (generally round and dish-shaped), the known presence of MIC in MNGP raw water systems, and historical issues with raw water system piping, the flaws were consistent with MIC. The bulk of the material surrounding these pits was above the ASME B31.1 minimum wall thickness with the pits comprising less than one percent of the overall circumference. The acceptable, minimum wall thickness of 0.067 inches assumes uniform thickness through the entire circumference of the pipe. Since the majority of the piping was much greater than the minimum wall thickness, the MIC pits would not result in failure of the piping based on historical data. The MIC consumption rate for these pits was estimated as 0.010 inches per year. Therefore, the piping was projected to maintain its leak integrity for at least 2 years. The issue was entered into the CAP and in February 2018, a site work order replaced the piping.

- In August 2017, a small pinhole leak (approximately 1 drop per minute, dpm) was identified on the fire protection piping in the intake tunnel. UT inspections were performed that characterized the condition of the fire piping at and around the leak location. Previously identified MIC pits from 2013 were located to assess the rate of pit growth. Also, UT inspections were performed a few feet upstream and downstream of the sample area. The MIC pits that were identified were small in area and the piping wall thickness quickly returned to nominal as measured when going away from the pit center. This showed that the majority of the piping was maintaining its structural strength due to having sufficient wall thickness. Also, the pits did not line up either longitudinally or circumferentially, which showed that the piping was not susceptible to failure from a guillotine type of break or from a split in the axial direction. Based on this, the fire piping in the intake tunnel was acceptable for continued use, even with the through-wall, pin-hole leak. A housekeeping patch was applied over the leak.

- At the end of 2017, a significant portion of the INS FIR System piping was replaced, including the degraded sections discussed above, with new like-for-like carbon steel piping and new valves.

- In April 2019, during an aging management walkdown for the FIR System, degraded coating was found on the piping above a hose station near the west wall on the turbine floor and a hose station in the heating boiler room. Piping had paint flaking off and surface rust, but no substantial piping material loss was present such that the degraded coating did not impact the performance of the associated hose stations. The finding was entered into the CAP and a work order generated to perform cleaning and recoating of the piping.

- In August 2019, during the replacement of a warehouse FIR System water gong, the drain line and orifice were found plugged with buildup of silt/debris approximately 3 inches thick. The finding was entered into the CAP and the drain line and orifice were removed, cleaned, and then reinstalled and a step was added to the preventive maintenance activity to inspect the drain and orifice for obstructions.

- MNGP addressed the ISG-2012-01 concerns of wall thinning due to erosion by updating the LR Flow-Accelerated Corrosion Program procedures to inspect locations susceptible to wall thinning due to erosion. In December 2020, a FIR System basket strainer was replaced. The basket strainer had been installed since original plant construction and had experience wall thinning due to erosion.

- Program Health Reports

  - The MNGP Fire Protection Program Health Report published in January 2021 was reviewed. All categories were graded as “Green.” Specifically, the fire suppression system category had no findings identified.

  - The MNGP Service Water / MIC Program Health Report published in January 2021 was reviewed. All categories were graded as “Green,” including categories for SR leaks, NSR leaks, components in service based on Code Case N513 evaluation, and components in-service utilizing temporary Code repair methods. At the time of the health report publication, no leaks had occurred on the in-scope FIR System piping within the previous 12 months.

  - The MNGP Buried Pipe Program Health Report published in January 2021 was reviewed. All categories were graded as “Green.” At the time of the health report publication, no leaks had occurred on the buried piping, which included FIR System piping, within the previous 12 months.

- NRC Reviews and Inspections

  On July 16, 2010, the NRC completed Post-Approval Site Inspections for License Renewal for MNGP in accordance with NRC Inspection Procedure 71003. The NRC inspectors did not identify any findings or violations related to the fire water system program.

- Self-Assessments

  - A self-assessment performed in February 2010, determined that with respect to the Fire Water System AMP, a license renewal attribute was added to several work orders which were replacing fire protection nozzles.

- A self-assessment performed in September 2019, identified two occurrences of pitting in FIR System piping, one FIR System pinhole leak, and a plugged FIR System drain line and orifice, which had occurred since 2017.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and no findings were identified related to the MNGP Fire Water System AMP.

The MNGP Fire Water System AMP is informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Fire Water System AMP with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended functions of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The MNGP Outdoor and Large Atmospheric Metallic Storage Tanks AMP is a new AMP that will manage the aging effects on the external and internal surfaces of CST tanks, T-1A and T-1B. Each tank has a capacity of 230,000 gallons, is made of carbon steel, is insulated, and rests on a foundation of concrete and soil.

This AMP includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. Sealant or caulking is used for outdoor tanks at the tank bottom interface.

This AMP will manage loss of material by conducting periodic internal and external visual inspections. Inspections of caulking and/or sealant are supplemented with physical manipulation. Thickness measurements of tank bottoms are conducted to detect degradation (e.g., loss of material on the inaccessible external surface). The external surfaces of insulated tanks will be periodically inspected using a sampling of inspection points. Internally coated/lined surfaces are managed for the loss of coating or lining integrity separately by the MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP (B.2.3.28). The concrete foundation and sealant at the base of the tanks are managed by the MNGP Structures Monitoring AMP (B.2.3.33). The tank internals exposed to treated water including tank walls and bottoms will be visually inspected per the MNGP One-Time Inspection AMP (B.2.3.20).

Inspections will be conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions. Periodic external visual inspections will be performed each outage to confirm that insulation, insulation jacketing, sealant, and caulking are intact. Inspections include locations where potential leakage past the insulation could be accumulating. The visual inspection of sealant and caulking are supplemented with physical manipulation to detect degradation. The visual inspections of the tank internals exposed to air and condensation environment, and the tank bottom thickness measurements will be performed each 10-year period no earlier than 10 years prior to the SPEO.

Where practical, identified degradation will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the component intended function throughout the SPEO based on the projected rate of degradation. Applicable OE or inspection results may also be used to justify performing the periodic inspections more frequently.

Acceptance criteria for the tank to concrete interface inspection are to confirm there are no signs of aging as a result of water intrusion. Any degradation of paints, coatings, or evidence of corrosion will be reported, and further evaluation is required to determine if repair or replacement will be conducted. When the acceptance criteria are not met, the condition is entered into the CAP for evaluation and determination of corrective actions to ensure that the intended functions of the tanks will be maintained under all CLB design conditions. Results will be evaluated against acceptance criteria for the in-scope tanks to confirm that the timing of the subsequent inspections will maintain the component intended functions throughout the SPEO based on the projected rate of degradation.

NUREG-2191 Consistency

The MNGP Outdoor and Large Atmospheric Metallic Storage Tanks AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M29, *Outdoor and Large Atmospheric Metallic Storage Tanks*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. There have been instances within the nuclear industry that have involved tank defects such as wall thinning, cracks, pinhole leaks, through-wall flaws, as well as internal blistering, coating delamination, rust stains, and holiday which are frequently identified on tank bottoms. With respect to these issues, MNGP has experienced some coating/paint degradation and some rusting/corrosion on the subject tanks, but none that impacted the function of the tanks.

Plant-Specific Operating Experience

During inspection of the roofs of the CST tanks T-1A and T-1B (2011 and 2009, respectively), rust and degradation were identified in several locations of the insulation. Degraded top coating and insulation were replaced per WOs.

In 2014, a portion of the base of each CST tank was visually inspected with the insulation removed. Paint flaking and multiple areas of minor surface rust was found, but no appreciable material loss was noted, and no active leak was identified. Rust was removed and the affected portions of the CST tank exterior were repainted to prevent further degradation.

In 2016, pitting was identified near the bottom of the external side of a CST tank. Inspections were completed on both CST tanks' external wall with the insulation removed. The wall was painted to help with corrosion prevention, and no other areas were identified that required a repair.

In 2016, exterior coating for each CST tank was replaced based on a finding documented in the CAP. Rust was removed from each CST tank exterior, then the exterior was repainted in accordance with industry practice to protect the base metal from corrosion.

In 2017, both CST tanks were cleaned and internally inspected based on a finding documented in the CAP. Interior walls were visually inspected, and UT inspection was utilized for the tank floors. All UT results were within specifications, and minor degradation of the internal coating was identified and repaired.

These plant-specific OE items provide objective evidence that inspection, engineering, and maintenance activities are effective at identifying and correcting identified deficiencies, and that deficiencies are entered into the CAP for evaluation and follow-up actions. These actions provide assurance that the CST tanks will be able to continue to perform their intended function during the SPEO.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The MNGP Outdoor and Large Atmospheric Metallic Storage Tanks AMP will be informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Outdoor and Large Atmospheric Metallic Storage Tanks AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.18 Fuel Oil Chemistry

The MNGP Fuel Oil Chemistry AMP is an existing AMP that manages loss of material in tanks, components, and piping exposed to an environment of diesel fuel oil by verifying the quality of fuel oil and controlling fuel oil contamination as well as periodic draining, cleaning, and inspection of tanks. This AMP includes surveillance and maintenance procedures to mitigate corrosion of components exposed to a fuel oil environment.

This objective is accomplished by offload sampling and testing of new fuel oil and periodic sampling and chemical analysis of the stored fuel oil. The AMP will also perform periodic draining, cleaning, internal visual inspections on the internal surfaces of the diesel oil storage tanks and EDG day tanks. Visual inspections will also be performed on the accessible exterior portions of the diesel oil storage tank. Volumetric (UT) thickness measurements will be performed routinely on the diesel oil storage tank, diesel fire pump day tank, and EDG base tanks. UT thickness measurements will also be performed on the EDG day tanks on affected areas if corrosion is identified during internal visual inspections. UT thickness measurements are performed ensuring the tank bottom and other areas where sludge may build up are included to the extent possible.

The MNGP Fuel Oil Chemistry AMP includes (a) surveillance and maintenance procedures to mitigate corrosion and (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the MNGP Technical Specifications and Technical Requirements Manual. Guidelines of the American Society for Testing and Materials (ASTM) Standards are also used. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining and/or cleaning of tanks and by verifying the quality of new fuel oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, the effectiveness of the fuel oil chemistry controls is verified to provide reasonable assurance that significant degradation is not occurring. The MNGP One-Time Inspection AMP (B.2.3.20) is also used to verify the effectiveness and supplement this AMP.

Components within the scope of the MNGP Fuel Oil Chemistry AMP are the diesel fuel oil storage tanks, piping, and other metal components subject to AMR that are exposed to an environment of diesel fuel oil. The tanks within the scope of this AMP are the diesel oil storage tank (DOST), EDG day tanks, the base tanks, and the diesel fire pump day tank.

NUREG-2191 Consistency

The MNGP Fuel Oil Chemistry AMP, with enhancements, will be consistent with one exception to the 10 elements of NUREG-2191, Section XI.M30, *Fuel Oil Chemistry*.

Exceptions to NUREG-2191

The MNGP Fuel Oil Chemistry AMP includes the following exception to the NUREG-2191 guidance:

(1) The size and the design of the diesel fire pump day tank and EDG base tanks make it difficult to perform the required draining, cleaning, internal inspections, or volumetric inspection of the bottom thickness. Accordingly, MNGP will take an exception to the cleaning and inspection guidance specified in Element 4 of the NUREG-2191, XI.M30 AMP. As an alternate to the GALL-SLR XI.M30 AMP Element 4 requirements, MNGP will drain and clean the diesel fire pump day tank and EDG base tanks to the extent practical. Visual inspection of accessible locations of the tank internals will be performed. Volumetric inspections to extent practical will continue to be performed on the diesel fire pump day tank.

Enhancements

The MNGP Fuel Oil Chemistry AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than six months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Update or create new implementing procedure(s) to include periodic checks for and removal of water accumulation in the Diesel Fire Pump Day Tank.
3. Parameters Monitored or Inspected 5. Monitoring and Trending	Update or create new implementing procedure(s) to include sampling of the day tanks and base tanks, in addition to the samples taken from the Diesel Oil Storage Tank, subject to the same standards. Ensure that the sampling of all diesel oil storage tanks specifically monitors the following parameters for trending purposes: water content, sediment content, biological activity, and total particulate concentration.
5. Monitoring and Trending	Ensure visual and volumetric inspection procedures for this AMP include the following monitoring and trending features: o Identified degradation is projected until the next scheduled inspection, where practical. o Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions

Element Affected	Enhancement
	throughout the SPEO based on the projected rate of degradation.
6. Acceptance Criteria	All new and existing visual and volumetric inspection procedures for this AMP will include the following acceptance criteria features: o Corrective actions are taken if microbiological activity is detected. o Any degradation of tank internal surfaces is reported and evaluated using the CAP. o Thickness measurements of the diesel oil storage tank bottoms are evaluated against the design thickness and corrosion allowance.
7. Corrective Actions	Update implementing procedure(s) to include the addition of biocide to the fuel oil when the presence of biological activity is confirmed, or if there is evidence of MIC.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- The OE at some plants has included identification of water in the fuel, particulate contamination, and biological fouling. In addition, when a diesel fuel oil storage tank at one plant was cleaned and visually inspected, the inside of the tank was found to have unacceptable pitting corrosion (>50 percent of the wall thickness), which was repaired in accordance with American Petroleum Institute (API) 653 standard by welding patch plates over the affected areas. A review of MNGP OE from 2012 to present identified an inspection and evaluation performed in March 2013 that identified minor corrosion on the diesel oil storage tank. Ultrasonic thickness measurements determined that the wall thickness remained well above the minimum requirement. The corrosion rate was projected and concluded that the remaining life of the tank was 189 years.

Plant-Specific Operating Experience

The Fuel Oil System is routinely reviewed for water content, and no adverse instances have been noted. The fuel oil tanks and piping are routinely inspected and have not had any significant findings or degradation in recent history.

A search performed of MNGP OE for SLR, spanning the time frame from January 2012 through June 2021, returned the following ARs related to the fuel oil chemistry program. All items below were entered into the CAP for proper resolution.

- In January 2012, when performing a review of laboratory analysis results on a fuel oil sample from the diesel fire pump fuel oil tank taken in December 2011, the system engineer determined that the sample had not been sent to the laboratory and therefore results were not available for review. The sample was located in a fireproof cabinet and was promptly sent to the laboratory, and the due date for analysis results (March 2012) was not threatened. An evaluation of the processes identified a gap in the procedure with respect to ensuring shipping documents are processed in a timely manner. The procedure was revised to include a step for filling out the appropriate shipping form and ensure that samples are delivered to the shipping/receiving warehouse. This OE demonstrates that MNGP evaluates the root cause of findings that arise, and implements procedural changes, when necessary, to avoid future findings.

- In September 2012, an evaluation determined that the multi-level procedure for removing samples of fuel oil from the storage tank was not suitable when checking for accumulated water, which would collect at the bottom of the tank, if present. An evaluation was performed of prior sampling results and no evidence of microbiological growth was identified. Samples are now taken from a separate dewatering sample rig when testing for accumulated water. This OE demonstrates that actions are taken when necessary to satisfy testing requirements.

- In December 2012, during a review of sample results following a revision to the implementing procedure that governs quality checks of new fuel oil, there was a discrepancy found between the specifications provided in the procedure and those shown in the analysis report. The recent procedure change was evaluated, and the guidance on parameters to be monitored was determined to be unclear. A procedure change request was initiated to revise the procedure. This OE demonstrates that procedures are evaluated and updated as necessary to ensure that sample results are evaluated properly to maintain fuel oil quality.

- In March 2013, an inspection and evaluation were performed on the DOST (T-44) in accordance with API 653. Light under deposit corrosion was observed along the bottom of the tank and two isolated areas of external corrosion were found. Ultrasonic thickness measurements were recorded and revealed no significant metal loss. An evaluation was performed to project the corrosion rate and estimate when the minimum thickness of the tank would be reached. The remaining life left at the time was determined to be 189 years, which far exceeds the SPEO. This OE demonstrates that findings are evaluated and projected to ensure that the tank remains functional.

- In January 2015, the sample results from the DOST showed an increasing trend for particulates. The sample result was slightly below the acceptance criterion whereas earlier results were well below the limit. An evaluation of historical sample results found that particulate contents began slowly increasing in 2015. A work request was initiated to take another sample to verify the results and observed trend. A subsequent sample in February 2015 confirmed that the particulate content returned to well below the limit.

- In March 2019, the quarterly fuel oil sample from the DOST (T-44) came back with a calorific value gross heat (HHV) in BTU/gal slightly below the required value. Conversely, the calorific value in BTU/lb was within the normal range. Since the value in BTU/gal is derived from the BTU/lb value using the density of the fuel oil, the sample laboratory was determined to have miscalculated the BTU/gal value due to the use of an incorrect density. Recalculating the BTU/gal value using the correct density returned a calorific value in BTU/gal that was within the normal range. The vendor was asked to provide a corrected report. This OE demonstrates that sampling results are evaluated effectively and any results that do not meet acceptance criteria are further evaluated to determine the underlying cause.

- In July 2019, the control room unexpectedly received an unexpected high level alarm on the DOST (T-44). Procedures were followed to check for the presence of water inside the tank. No water accumulation was found. An evaluation found that the level rose slowly. The slow level rise was attributed to thermal expansion due to a rise of 15°F to 20°F in ambient temperature in that timeframe. This OE demonstrates that steps are taken to ensure there is no water accumulation in the DOST when there is an unexplained rise in tank level.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no major findings were identified related to the MNGP Fuel Oil Chemistry AMP. One minor finding was identified that required the AMP basis document reference to be updated to the latest revision. A procedure change request was processed to complete the update.

The MNGP Fuel Oil Chemistry AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Fuel Oil Chemistry AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.19 Reactor Vessel Material Surveillance

The MNGP Reactor Vessel Material Surveillance AMP is an existing condition monitoring program that monitors the loss of fracture toughness due to neutron embrittlement of the ferritic RPV beltline materials (vessel materials with a projected neutron fluence greater than 1.0×10^{17} n/cm^2 (E >1 MeV) in a reactor coolant and neutron flux environment. The AMP utilizes surveillance capsules that are located near the inside wall of the RPV beltline region to duplicate, as closely as possible, the neutron spectrum, temperature history, and neutron fluence of the RPV inner surface. The fluence lead factor based on the location of the surveillance capsules allows them to achieve a neutron fluence exposure earlier than the RPV. Thus, the surveillance capsules can be withdrawn and tested prior to the RPV reaching the neutron fluence of interest.

The MNGP Reactor Vessel Surveillance Program is part of the Boiling Water Reactor's Vessel Internals Project (BWRVIP) ISP. MNGP committed to use the ISP in place of its existing surveillance program, as indicated in the license amendment issued by the NRC regarding the implementation of the BWRVIP Reactor Pressure Vessel ISP.

The program provides sufficient material data and dosimetry to: (a) monitor irradiation embrittlement neutron fluences greater than the projected neutron fluence at the end of the SPEO, and (b) provide adequate dosimetry monitoring during the operational period.

The program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in upper-shelf energy as a function of neutron fluence and irradiation temperature. RPV beltline material test results provide reactor vessel material fracture toughness data for the neutron irradiation embrittlement TLAAs (e.g., upper-shelf energy, P-T limits evaluations, etc.). The RPV beltline material surveillance capsules are removed at various exposure intervals for monitoring and trending purposes and works in conjunction with the MNGP Neutron Fluence Monitoring (B.2.2.2) program for updating fluence embrittlement information. See Section 4.2 of the SLRA for discussion of the TLAAs associated with neutron irradiation embrittlement.

Surveillance capsules are withdrawn, tested, and results reported in accordance with 10 CFR Part 50, Appendix H and ASTM E 185-82, to the extent practicable, for the configuration of the specimen in the capsule. Any changes to the surveillance capsule withdrawal schedule as part of the ISP must be approved by the NRC prior to implementation per 10 CFR Part 50, Appendix H. Specimens from tested capsules and withdrawn untested capsules are maintained in storage for possible reconstitution or re-insertion. Abnormal or unexpected results are entered into the CAP for engineering evaluation.

The MNGP AMP consists of three surveillance capsules initially located at 30°, 120°, and 300° at the core mid-plan. In 1981, the capsule at 30° was removed with one specimen set tested and the second specimen set installed in the Unit 1 Prairie Island Nuclear Generating Plant RPV for continued irradiation at an accelerated fluence. The specimens installed in the Unit 1 Prairie Island Nuclear Generating Plant RPV were removed and tested in 1996.

Under the ISP program, the MNGP 300° surveillance capsule was withdrawn in 2007 and tested in 2008, per BWRVIP-86A, Revision 1-A. For weld material MNGP uses the information from the River Bend Station and from the BWROG Supplemental Surveillance Program (SSP). The MNGP ISP representative weld material (5P6756) will be withdrawn and tested in 2030. To support the current PEO, the final MNGP surveillance capsule was withdrawn in 2021 per the ISP.

For the SPEO, as part of this SLRA, MNGP requests NRC approval per the NRC staff's BWRVIP-321-A safety evaluation and per 10 CFR Part 50, Appendix H, Paragraph III.B.3 to implement BWRVIP-321-A, *Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR)* (Reference ML21152A086, non-proprietary version; Reference ML21152A084, proprietary version) to meet the requirements of 10 CFR Part 50, Appendix H. The NRC final Safety Evaluation for BWRVIP-321 (enclosed with BWRVIP-321-A) concluded that BWRVIP-321, including supplemental information, provides an acceptable means to adequately address the needs for surveillance data for BWR licensees through the end of a facility's 80-year operating license.

MNGP is projected to achieve approximately 72 EFPY of operation at the end of the SPEO. MNGP has validated per Section 9.2 of BWRVIP-321-A that additional surveillance data from the ISP supplemental SLR (SSLR) capsule materials is needed to bound the MNGP SLR fluence needs for 80 years.

The ISP capsule insertion, withdrawal, and testing schedule is as described in Section 8 of BWRVIP-321-A. Because the selection of materials to be reconstituted and tested will depend on which BWRs pursue SLR and need for additional surveillance data, the BWRVIP will notify the NRC of test plans and timeline for reporting test results as described in Section 10.3.2 of BWRVIP-321-A. Per Section 4, Tables 4-15 and 4-16 of the BWRVIP, at least one capsule addressing the SPEO projected fluence will be tested with a capsule neutron fluence of one to two times the vessel neutron fluence of interest at the end of the SPEO.

NUREG-2191 Consistency

The MNGP Reactor Vessel Material Surveillance AMP, with enhancement, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M31, *Reactor Vessel Material Surveillance*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Reactor Vessel Material Surveillance AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancement is to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program; 3. Parameters Monitored or Inspected; 4. Detection of Aging Effects; and 5. Monitoring and Trending	Implement BWRVIP-321-A, *Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR)*, upon obtaining NRC approval for MNGP to use BWRVIP-321-A to maintain compliance with 10 CFR Part 50, Appendix H.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- NRC Regulatory Issue Summary 2014-11, *Information on Licensing Applications for Fracture Toughness Requirements for Ferritic Reactor Coolant Pressure Boundary Components*, provided industry guidance on the scope of detail of information that should be provided in the reactor vessel facture toughness and associated P-T limits licensing applications to facilitate staff review. A CAP item was initiated to evaluate the industry OE against current equipment and processes. No actions were identified as a result of the OE evaluation and no additional actions were necessary.

- In 2015, a CAP item was initiated to evaluate industry OE concerning an NRC 10 CFR Part 21 report concerning a damaged surveillance capsule. MNGP evaluated the issue and determined it described a human performance event that was not applicable to MNGP. This 2015 10 CFR Part 21 notification was a precursor to NRC IN 2016-02 discussed below.

- NRC IN 2016-02, *Improper Seating of Reactor Vessel Surveillance Capsules* (Reference ML15278A472), informed the industry of recent OE related to reactor vessel capsules that were not properly seated in their baskets and subsequently broke loose during plant operation. A CAP item was initiated to evaluate the industry OE. The evaluation determined the OE was applicable to MNGP with barriers in place to prevent a similar occurrence consisting of periodic inspection of the surveillance capsule holders and the remaining loaded surveillance capsule, the procedures for in-vessel visual inspection, the inspection results of the surveillance capsules, and the then planned activities for the surveillance capsules.

The above examples provide objective evidence that the program is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE.

Plant-Specific Operating Experience

- In 2018, a CAP item was initiated as a result of GEH notification to MNGP of an error in modeling of the core shroud neutron flux evaluations in that the core shroud was modeled as a perfect cylinder versus the actual design with a change in radius near the top of the active fuel level. In addition, the core bypass flow near the top guide had been modeled as water solid versus the actual behavior of a transition to steam. The finding was evaluated by MNGP via the corrective action process. The issue was confirmed to be bounded by the current analysis and that no change was required to the reactor vessel surveillance capsule withdraw schedule. Further, the evaluation determined the scheduled surveillance capsule withdrawal will provide the updated fluence data which will drive this item to resolution.

- In 2011, a CAP item was initiated to address identified issues concerning the RPV N2 nozzles (recirculation inlet nozzles) not being appropriately considered in the RPV P-T limit curves. The AR identified recent industry OE regarding a lack of clarity in the industry for what components should be considered for evaluation in the belt line region of the RPV. Since the discovery of this condition, MNGP pursued a PTLR. The MNGP PTLR updated the curves to address the conditions at that time including the additional data from the 300° surveillance capsule pull, the discovery of the N2 nozzles in the beltline and the extension of the beltline up into the third vessel plate. A conservative administrative limit was placed on the impacted RPV P-T limits curves to account for the impact of the N2 nozzles. The change to the P-T curves and approval of the PTLR was performed under MNGP License Amendment 172 (Reference ML13025A155). The PTLR was fully implemented, and all procedures were updated to reflect the new curves.

- In 2009, a CAP item was initiated when test results for a reactor material surveillance capsule indicated that the P-T limit curve in plant Technical Specifications was impacted resulting in the existing curve being non-conservative. The condition was evaluated with actions established including NRC notification and submittal of additional information to support the PTLR license amendment request (Reference ML12033A175).

The above examples provide objective evidence that the program monitors the reduction of fracture toughness of reactor vessel beltline materials due to neutron irradiation embrittlement and that findings are entered into the CAP with appropriate actions taken to evaluate and correct findings, as necessary.

These examples provide objective evidence of AMP effectiveness during the PEO and that the continued implementation of the Reactor Vessel Material Surveillance AMP will effectively manage aging by identifying degradation prior to failure or loss of intended function during the SPEO.

- In support of the Reactor Vessel Material Surveillance program, capsules have been withdrawn from the MNGP RPV, and tested in accordance with 10 CFR Part 50, Appendix H.

In 1981, the capsule at 30° was removed with one specimen set tested and the second specimen set installed in the Unit 1 Prairie Island Nuclear Generating Plant RPV for continued irradiation at an accelerated fluence. The specimens installed in the Unit 1 Prairie Island Nuclear Generating Plant RPV were removed and tested in 1996. The results of these surveillance specimen evaluations formed the basis for the revised Technical Specification operating limit changes reflected in License Amendment 106 (Reference ML020920252).

The BWRVIP Integrated Surveillance Program (ISP) which was initiated in 1999 was designed to replace the original plant-specific surveillance capsule programs with representative capsules in host BWR plants. MNGP committed to use the ISP in place of its existing surveillance programs, in the license amendment issued by the NRC regarding the implementation of the Boiling Water Reactor Vessel and Internals Project Reactor Pressure Vessel Integrated Surveillance Program. The ISP is described in BWRVIP-86-R1-A: BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan. MNGP is designated as a host plant and has withdrawn and tested capsules in 2007 and 2021.

Under the ISP program, a MNGP surveillance capsule was pulled in 2007 and tested in 2008 that contained representative vessel plate materials. The 2008 capsule test results were used to update the P-T limits for the MNGP RPV through the end of the current PEO. MNGP transitioned the updated P-T limits from the technical specifications to a licensee controlled PTLR. The PTLR was approved for use under license amendment 172 issued February 27, 2013.

This OE provides objective evidence that participation in the ISP in accordance with the Reactor Vessel Surveillance program is used to effectively monitor the loss of fracture toughness of the RPV beltline materials due to neutron irradiation embrittlement.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Reactor Vessel Material Surveillance AMP. The review concluded that the AMP was effective in managing age-related degradation. Administrative findings associated with the management of the program were identified and were entered into the CAP.

The MNGP Reactor Vessel Material Surveillance AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Reactor Vessel Material Surveillance AMP, with enhancement, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.20 One-Time Inspection

The MNGP One-Time Inspection AMP is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the SPEO; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action. The MNGP One-Time Inspection AMP will manage the aging effects of loss of material due to crevice corrosion, general corrosion, MIC, and pitting corrosion, cracking due to SCC and IGSCC, and loss of heat transfer capability due to fouling.

The elements of the MNGP One-Time Inspection AMP include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and OE, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the SPEO. The inspection sample includes locations where the most severe aging effect(s) would be expected to occur. Inspection methods may include visual, surface or volumetric examinations, or other established NDE techniques.

The inspection includes a representative sample of each population (defined as components having the same material, environment, and aging effect combination) and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. A representative sample size is 20 percent of the population or a maximum of 25 components. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection is included as part of the program documentation. Factors that will be considered when choosing components for inspection are time in service, severity of operating conditions, and OE.

Examination techniques are established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria is based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. Additional inspections are conducted if one of the inspections does not meet acceptance criteria. There will be 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 is inspected, whichever is less.

The acceptance criteria for this program considers both the results of observed degradation during current inspections and the results of projecting observed degradation of the inspections for each material, environment, and aging effect combinations. Acceptance criteria are based on applicable ASME Code or other appropriate standards, design basis information, or vendor-specified requirements and recommendations (e.g., ultrasonic thickness measurements are compared to predetermined limits); however, crack-like indications are not acceptable. Where it is practical to project observed degradation to the end of the SPEO, the projected degradation will not: (a) affect the intended function of a system, structure, or component; (b) result in a potential leak; or (c) result in heat transfer rates below that required by the CLB to meet design limits. Where measurable degradation has occurred, but acceptance criteria have been met, the inspection results are entered into the CAP for future monitoring and trending.

The MNGP One-Time Inspection AMP is used to verify the effectiveness of the MNGP Water Chemistry (B.2.3.2), Fuel Oil Chemistry (B.2.3.18), and Lubricating Oil Analysis (B.2.3.25) AMPs. For steel components exposed to water environments that do not include corrosion inhibitors as a preventive action or steel components that do not have wall thickness measurement examinations conducted of a representative sample of each environment between the 50th and 60th year of operation, the MNGP One-Time Inspection AMP will be used to verify that long-term loss of material due to general corrosion will not cause a loss of intended function (e.g., pressure boundary, leakage boundary (spatial), and structural integrity). For components susceptible to long-term loss of material due to general corrosion, wall thickness will be measured with a volumetric (UT) technique.

The MNGP One-Time Inspection AMP will address potentially long incubation periods for certain aging effects and will provide a means of verifying that an aging effect is either not occurring or progressing so slowly as to have a negligible effect on the intended function of the structure or component. Situations in which additional confirmation is appropriate include: (a) an aging effect is not expected to occur, but the data are insufficient to rule it out with reasonable confidence; or (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than generally expected. For these cases, confirmation demonstrates that either the aging effect is not occurring or that the aging effect is occurring very slowly and does not affect the component or structure intended function during the SPEO based on prior OE data.

The MNGP One-Time Inspection AMP will also include other components and materials where the environment in the SPEO is expected to be equivalent to that in the prior operating period and for which no aging effects have been observed. From these lists of components, a sample of the population will be selected for inspection as part of the MNGP One-Time Inspection AMP.

The inspections will be completed before the end of the current operating term to provide reasonable assurance that the aging effect will not compromise any intended function during the SPEO. The inspections will be timed to allow the inspected components to attain sufficient age such that the aging effects with long incubation periods (i.e., those that may affect intended functions near the end of the SPEO) are identified. Any corrective actions will be implemented through the CAP. The AMP may include a review of routine maintenance, repair, or inspection records to confirm that selected components have been inspected for aging degradation within the recommended time period for the inspections related to the SPEO, and that significant aging degradation has not occurred.

The MNGP One-Time Inspection AMP does not address loss of material due to selective leaching. Loss of material due to selective leaching is addressed in the MNGP Selective Leaching AMP (B.2.3.21). The MNGP One-Time Inspection AMP also does not address Class 1 piping less than 4 inches nominal pipe size, since that piping is addressed in the MNGP ASME Code Class 1 Small-Bore Piping AMP (B.2.3.22).

NUREG-2191 Consistency

The MNGP One-Time Inspection AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M32, *One-Time Inspection*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

The elements that comprise inspections associated with this program (the scope of the inspections and inspection techniques) are consistent with industry practice. OE with detection of aging effects is adequate to demonstrate that the program is capable of detecting the presence or noting the absence of aging effects in the components, materials, and environments where one-time inspection is used to confirm system-wide effectiveness of another preventive or mitigative AMP.

Recent industry OE was reviewed from the SLR SERs for the first three submitted SLRAs. Two main points of interest are a) ensuring that the One-Time Inspection AMP is not used for managing aging of systems or components with known age-related degradation, and b) ensuring that one-time inspections are completed on steam generator components as necessary (not applicable to MNGP). The MNGP One-Time Inspection AMP will not be used for structures or components subjected to known aging mechanisms based on a review of plant-specific and industry OE.

Plant-Specific Operating Experience

- A focused self-assessment in 2010 identified that sufficient documentation did not exist to adequately demonstrate that the One-Time Inspection AMP had been performed on a representative sample to justify conclusions as to the effectiveness of the program. The finding was placed into CAP which validated sampling of each material/environment group and provided sample selection basis document for the One-Time Inspection AMP. Revised selection groups for the One-Time Inspection AMP, sample selection results, and references to corrective actions and follow-up examinations, as necessary, were also provided. One-time inspections were performed prior to the PEO of the initial license renewal in accordance with NUREG-1801, XI.M32, *One-Time Inspection*. All components within the scope of this program were grouped based on material, environment and aging effects requiring management, and component samples for inspection were chosen using an expert panel and review of plant documentation. Representative samples were selected for the aging effects of interest, and work orders were generated for the inspections. Evaluation criteria were identified for each component inspected based on manufacturer's specifications and/or industry standards. Inspection results which identified wall thickness less than evaluation criteria, or other relevant indications were entered into the CAP. Any indications of cracking were also entered into the CAP. Evaluation under the CAP determined whether there was a failure to perform the intended function, whether to perform follow-up examination, and whether to expand the sample size and sample locations.

The inspection results for each group confirmed that the managed aging mechanisms would not affect the intended functions of the components during the PEO.

- Routine inspections during maintenance activities have been performed on in-scope components applicable to the MNGP One-Time Inspection AMP. OE related to the MNGP Water Chemistry (B.2.3.2), Fuel Oil Chemistry (B.2.3.18), and Lubricating Oil Analysis (B.2.3.25) AMPs are stated in the respective AMPs and are summarized below.
  - The MNGP Water Chemistry AMP mitigates loss of material due to aging effects in components exposed to a treated water and treated borated water environment. The plant-specific OE relevant to the MNGP Water Chemistry AMP was primarily related to chemistry parameters with above normal readings, such as sulfates, and chlorides, but no specific age-related findings were identified.
  - The MNGP Fuel Oil Chemistry AMP minimizes the introduction and presence of contaminants in the plant fuel oil systems that could cause aging of components. The MNGP Fuel Oil Chemistry AMP primarily listed OE associated with received fuel oil and sediments/water content found in the in-scope tanks, but no specific age-related findings were identified.
  - The MNGP Lubricating Oil Analysis AMP identified instances where water and particulate contaminants were found in the lubricating oil. The plant-specific OE relevant to the MNGP Lubricating Oil Analysis AMP was primarily related to bearing/lubricating oil being an abnormal color for a variety of reasons, but no OE was found related to aging from lubricating oil contamination.
- NRC performed Phase I and II of post-approval site inspection for LR in 2009 and 2010. NRC inspectors interviewed the program owner, reviewed implementing procedures and records of completed inspections.
  - The NRC inspectors identified instances where WOs were performed with procedures not specified in the One-Time Inspection Methods program document. MNGP also documented instances where inspections were

conducted by personnel who were not certified in accordance with station procedures. The inspections conducted by unqualified personnel and procedures were determined to be a performance deficiency of minor significance that did not result in components that would exceed their acceptance criteria. No further action was required by this finding.

- The inspectors identified inspections where measured wall thickness was below the evaluation threshold, and questions regarding procedural adequacy for identifying pitting corrosion. The inspectors determined the components that were dispositioned without a proper aging evaluation would not exceed their engineering evaluation minimum wall thickness value during the entire PEO and the components would perform their intended functions based on a linear degradation analysis. In addition, after rigorous research, the inspectors could not locate an industry accepted method to detect pitting corrosion. This finding was determined to be of minor significance, and no further action was required.
- The inspectors identified a potential failure to follow procedure during an NDE exam for the One-Time Inspection program. Per the NRC Phase I inspection report, the finding was documented as an NRC URI, and was closed via issuance of an NRC letter (Reference ML102450165). Immediately following the occurrence, the examiner validated the readings that had been taken by demonstrating on the calibration block that the variation from the procedure had no measurable effect on the reading. Additionally, the examiner was coached and MNGP re-enforced expectations related to procedural compliance with personnel involved. A condition evaluation was performed, and extent of condition was determined with inspections performed by the examiner evaluated. Additionally, two inspections performed by the examiner for the One-Time Inspection program were re-performed to ensure that the procedures had been followed accurately.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The MNGP One-Time Inspection AMP will be informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP One-Time Inspection AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.21 Selective Leaching

The MNGP Selective Leaching AMP is an existing AMP that has the principal objective to manage the aging effect of loss of material due to selective leaching.

The MNGP Selective Leaching AMP includes inspections of components made of gray cast iron, ductile iron, and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to a raw water, closed-cycle cooling water, treated water, waste water, or soil environment. For closed-cycle cooling water and treated water environments, the AMP includes one-time visual inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques (e.g., chipping, scraping). For raw water, waste water, and soil environments, the AMP includes opportunistic and periodic visual inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques. Destructive examinations of components to determine the presence of and depth of dealloying through-wall thickness are also conducted. These techniques can determine whether loss of material due to selective leaching is occurring and whether selective leaching will affect the ability of the components to perform their intended function for the SPEO.

Each of the one-time and periodic inspections for the various material and environment populations comprises a 3 percent sample or a maximum of 10 components. For each material and environment population with 35 or more susceptible components, two destructive examinations will be performed in each 10-year inspection interval. For each material and environment population with less than 35 susceptible components, one destructive examination will be performed in each 10-year inspection interval.

The selective leaching process involves the preferential removal of one of the alloying components from the material. Dezincification (loss of zinc from brass) and graphitization or graphitic corrosion (removal of iron from gray cast iron and ductile iron) are examples of such a process. Susceptible materials exposed to high operating temperatures, stagnant-flow conditions, and a corrosive environment (e.g., acidic solutions for brasses with high zinc content and dissolved oxygen) are conducive to selective leaching. A dealloyed component often retains its shape and may appear to be unaffected; however, the functional cross-section of the material has been reduced. The aging effect attributed to selective leaching is loss of material because the affected volume has a permanent change in density and does not retain mechanical properties that can be credited for structural integrity.

The inspection acceptance criteria are as follows:

a. For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide.

b. For gray cast iron 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.

d. The components meet system design requirements such as minimum wall thickness, when extended to the end of the SPEO.

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 SPEO, additional inspections are performed 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. The number of additional inspections is equal to the number of failed inspections for each material and environment population, with a minimum of five additional visual and mechanical inspections when visual and mechanical inspections did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria.

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. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next RFO interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

The MNGP Selective Leaching AMP implementation and pre-SPEO inspections will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO. The pre-SPEO inspections will start no earlier than 10 years prior to the SPEO.

NUREG-2191 Consistency

The MNGP Selective Leaching AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M33, *Selective Leaching*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Selective Leaching AMP will be enhanced as follows, for alignment with NUREG 2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Update implementing procedure(s) or create new procedure to include the inspection of susceptible components exposed to treated water, Closed-Cycle Cooling Water, and waste water, or buried in soil.
4. Detection of Aging Effects	Update implementing procedure(s) or create new procedure to perform one-time inspections of a representative sample of each population (material/environment combination) for components exposed to closed-cycle cooling water or treated water. In the 10-year period prior to the SPEO, a sample of 3 percent of the population or a maximum of 10 components per population will be visually and mechanically (for gray cast iron and ductile iron components) inspected. Inspections, where possible, will focus on the bounding or lead components most susceptible to aging based on time-in-service and severity of operating conditions for each population.
4. Detection of Aging Effects	Update implementing procedure(s) or create new procedure to perform periodic inspections for components exposed to raw water, waste water, or soil. For raw water and waste water environments, the populations may be combined as long as an evaluation is conducted to determine the more severe environment and the inspections and examinations are conducted on components in the most severe environment, with one inspection being conducted in the less severe environment. Periodic inspections will be conducted in the 10-year period prior to the SPEO and in each 10-year period during the SPEO. In these periodic inspections, a sample of 3 percent of the population or a maximum of 10 components per population will be visually and mechanically (for gray cast iron and ductile iron components) inspected. When inspections are performed on piping, a 1-foot axial length section will be considered as one inspection. In addition, for sample populations with greater than 35 susceptible components, two destructive examinations will be performed in each material and environment population in each 10-year period. When there are less than 35 susceptible components in a sample population, one destructive examination will be performed for that population. Otherwise, a technical justification of the methodology and sample size used for selecting

Element Affected	Enhancement
	components for inspection will be included as part of the program's documentation. The number of visual and mechanical inspections may be reduced by two for each component that is destructively examined beyond the minimum number of destructive examinations recommended in each 10-year interval. Inspections, where possible, will focus on the bounding or lead components most susceptible to aging based on time-in-service and severity of operating conditions for each population. Opportunistic inspections may be credited as periodic inspections as long as the inspection locations selection criteria are met.
4. Detection of Aging Effects	Update implementing procedure(s) or create new procedure to include guidance on inspection parameters such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.
5. Monitoring and Trending	Update the implementing procedure(s) to include the following guidance: • Where practical, identified degradation is projected until the next scheduled inspection. • Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation.
6. Acceptance Criteria	Update implementing procedure(s) or create new implementing procedure to include the following acceptance criteria: • For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide; • For gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations;

Element Affected	Enhancement
	• The presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal while not taking credit for the material properties of the dealloyed portion of the component as part of the determination; and • The components meet system design requirements such as minimum wall thickness, when extended to the end of the SPEO.
7. Corrective Actions	Update implementing procedure(s) or create new implementing procedure to include the following guidance: • 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 SPEO, additional inspections are performed 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. The number of additional inspections is equal to the number of failed inspections for each material and environment population with a minimum of five additional visual and mechanical inspections when visual and mechanical inspections(s) did not meet acceptance criteria, or 20 percent of each applicable material and environment combination is inspected, whichever is less, and a minimum of one additional destructive examination when destruction examination(s) did not meet acceptance criteria. 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. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, in all cases, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number

Element Affected	Enhancement
	of inspections in the latter interval. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.
7. Corrective Actions	Update implementing procedure(s) or create new implementing procedure to require the removal of interferences to access or remove components most susceptible to selective leaching having difficult-to-access surfaces (e.g., heat exchanger shell interiors, exterior of heat exchanger tubes) if unacceptable inspection findings occur within the same material and environment population.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE program and takes appropriate corrective actions.

- Industry OE shows that selective leaching has been detected in components constructed from gray cast iron, ductile iron, brass, bronze, and aluminum bronze. The following OE from NUREG-2191 Section XI.M33 is relevant to MNGP:
    - During a one-time inspection for selective leaching, a licensee identified degradation in four gray cast iron valve bodies in the Service Water System exposed to raw water. The mechanical test used by the licensee to identify the graphitization was tapping and scraping of the surface. The licensee sand blasted two of the valve bodies and, after all of the graphite was removed; the licensee determined that the leaching progressed to a depth of approximately 3/32 inch. Based on the estimated corrosion rate, the licensee determined that the valve bodies had adequate wall thickness for at least 20 years of additional service (Reference ML14017A289).
    - Based on visual inspections conducted as part of implementing a one-time inspection for selective leaching, a licensee identified selective leaching in a gray cast iron drain plug of an auxiliary feedwater pump outboard bearing cooler. Possible selective leaching was also found on Multimatic valves on the underside of the clapper. As a result, the licensee incorporated quarterly inspections of the components in its periodic surveillance and preventive maintenance program (Reference ML13122A009).

- A licensee has reported occurrences of selective leaching of aluminum bronze components for an extensive number of years (Reference ML17142A263).
- NRC IN 94-59, Accelerated Dealloying of Cast Aluminum-Bronze Valves Caused by Microbiologically Induced Corrosion, August 17, 1994.
- The basis for inclusion of ductile iron in this GALL-SLR Report AMP XI.M33, along with OE examples, is cited in the GALL-SLR and SRP-SLR Supplemental Staff Guidance document (Reference ML16041A090).
- NRC IN 2020-04, OE Regarding Failure of Buried Fire Protection Main Yard Piping, December 17, 2020

  As a result of this industry OE, MNGP performed an evaluation under the CAP of a section of fire protection loop piping that is located in saturated soil. The evaluation included an OE review, which identified a work order that included excavation of a hydrant located near the area of saturated soil. The work order found that external coatings were undamaged, and the threaded hardware was still usable, and concluded that the coating and Cathodic Protection Systems continued to provide adequate protection from corrosion. No evidence of selective leaching was found during the OE review. Furthermore, soil analysis demonstrated that the soil was homogenous and that the characteristics of the soil have negligible effects on the external corrosion rates at MNGP. Based on these findings, it was concluded that the section of piping was determined to be acceptable.

- Recent industry OE was reviewed from the SLR SERs for the first three submitted SLRAs (Turkey Point, Peach Bottom, and Surry).
  - The MNGP Selective Leaching AMP needs to ensure that one-time inspections are not selected when there are known issues with selective leaching in treated water or closed-cycle cooling water environments. In addition, if plant OE demonstrates significant issues with selective leaching, further inspections and exploratory work may be required to adequately manage selective leaching.
  - The MNGP Selective Leaching AMP needs to ensure that a process exists to evaluate difficult-to-access surfaces if unacceptable inspection findings occur within the same material and environment population.

Plant-Specific Operating Experience

Selective leaching has been identified in gray cast iron valves exposed to raw water during inspections performed in implementation of MNGPs initial renewed license. As a result, procedures were implemented to institute opportunistic inspections with the scope limited to the material and environment combination where selective leaching was found. After selective leaching was identified, scope expansion was utilized to perform additional inspections on susceptible components. All instances of selective leaching were identified prior to a loss of intended function and there have been no failures resulting from selective leaching. The following list contains specific examples of OE.

- In 2010, a diesel fire pump check valve was removed and retained for license renewal inspections. During the inspection, loss of material due to selective leaching was identified via destructive examination. This discovery prompted the generation of procedures to provide guidance for evaluating plant equipment when selective leaching is identified.

- In 2010, four components were inspected for evidence of selective leaching. The components had been previously removed from service and retained for inspection. They included two copper alloy sprinklers and two cast iron valves exposed to raw water. No indications of selective leaching were found on any of the components via visual inspection (VT-1) or scratch test.

- Also in 2010, a gray cast iron valve exposed to raw water was inspected for evidence of selective leaching as part of a scope expansion due to the earlier OE described above. The interior of the valve showed several nodules indicative of selective leaching. The valve was cross-sectioned and inspected. Visual examinations showed selective leaching on several areas of the cross-section.

- In 2012, an evaluation was performed to produce a long-term management strategy for selective leaching. This evaluation led to the establishment of the program as an ongoing program instead of a one-time inspection program including opportunistic inspections whenever work was performed on susceptible valves and systematic replacement of valves that exhibit signs of loss of material due to selective leaching. Subsequent OE, discussed below, indicates that the quarterly reviews for inspection opportunities were not adequately documented.

- In 2013, selective leaching inspections were performed on three valves that had been removed for replacement due to seat leak-by. All three valves showed minor selective leaching that did not challenge the pressure boundary. No further corrective actions were deemed necessary since the valves had already been replaced.

The above examples demonstrate that the existing selective leaching program at MNGP has effectively identified selective leaching and taken appropriate corrective actions as a result. As described below, there have been instances where reviews for opportunities for selective leaching inspections were not properly documented. The issue was initially identified as a result of a focused self-assessment performed during the License Renewal Phase 4 Inspection and was determined to be a result of a lack of proper turnover from the previous program owner. Completed copies of the selective leaching inspection form were unable to be located for inspections performed after the initial LR inspections performed in 2010. Corrective actions were taken to update the work order planning process procedure to include selective leaching inspections. A subsequent opportunity to perform a selective leaching inspection was missed. Further corrective actions were taken to ensure that future opportunities for selective leaching inspections were not missed. The following list provides specific corrective actions in greater detail.

- In 2019, during the License Renewal Phase 4 Inspection focused self-assessment (FSA), the Selective Leaching AMP strategy was determined to be unclear due to a lack of turnover from the previous program owner. As a result, the quarterly review of work orders for components susceptible to selective leaching had not occurred in at least a year. To prevent this from reoccurring, expanded guidance was added to the work planning procedure to ensure that the selective leaching form was included in the work plan. This guidance was specifically for components located in the material/environment combination where selective leaching had been identified when breeching the buried fire protection piping or wells and domestic water (WDW) floor drain piping. Procedure change requests were initiated to include the necessary changes to the work order planning procedure and to develop a new procedure that established the Selective Leaching of Materials Program as an opportunistic program. Furthermore, a selective leaching recovery plan was developed to bring the program up to current standards. The recovery plan includes, (1) a review of past work order records for selective leaching visual inspections, (2) reestablishing selective leaching as part of the maintenance planning process to ensure opportunistic inspections are occurring, and (3) performing OE evaluations to align with industry standards and best practices. This OE demonstrates the effectiveness of internal audits at MNGP to ensure that the program is informed and enhanced when necessary.

- In 2020, a documentation issue was identified when the selective leaching inspection form was unable to be found and completed copies of the form were unable to be located for inspections performed after the initial LR inspections performed in 2010, with the exception of one inspection performed in January 2020. As part of the evaluation, the form was properly cited for records retention in its governing procedure and that the work order planning process procedure was updated to include the opportunistic selective leaching inspections.

- During an OE review in 2020, a finding was identified between the scope of the MNGP Selective Leaching program and updated EPRI guidance, which included ductile iron as a material susceptible to selective leaching. The selective leaching opportunistic inspection procedure was revised to include the additional susceptible components. This OE demonstrates that MNGP effectively enhances the program when necessary through systematic and ongoing review of industry guidance.

- In 2020, an opportunistic inspection for evidence of loss of material due to selective leaching was performed on a basket strainer that had been removed from service. The basket strainer was cross sectioned for examination. Selective leaching was identified on several of the cross sections. Based on the location and amount of selective leaching seen, that there was no loss of intended function. An extent of condition evaluation was performed that identified two other strainers that experience similar conditions. Both of the additional strainers had been inspected in 2015 and no evidence of selective leaching was noted during the inspection or cleaning activities. Corrective actions were initiated to review and determine if the maintenance interval for these components was appropriate, and to evaluate the replacement of the basket strainers at the next maintenance opportunity. This OE demonstrates that the opportunistic inspections are effective in identifying selective leaching prior to a loss of intended function and that the program continues to perform extent of condition evaluations. Process improvements are still warranted to ensure that selective leaching inspections are performed and documented as a result of the extent of condition evaluations.

- In 2022, an opportunity was missed to inspect a basket strainer for evidence of selective leaching when it was inspected and cleaned. This finding was strictly related to documentation. The basket strainer was previously inspected in 2010, at which time no evidence of selective leaching was found. Recommended corrective actions include ensuring that the extent of condition evaluation described above was performed and for the new program owner to revisit corrective actions from prior related CAPs to determine whether additional action was required to prevent further recurrence. The program owner performed a search to identify upcoming inspection opportunities and added a step to a future work order to ensure that an inspection for selective leaching was performed during the preventive maintenance task. Also, a recurring (quarterly) task was set up to review upcoming work orders that perform work on components that are within the scope of the periodic Selective Leaching program. Once opportunities are identified, a model work order will be added to perform the selective leaching inspection.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Selective Leaching AMP.

The MNGP Selective Leaching AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Selective Leaching AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.22 ASME Code Class 1 Small-Bore Piping

The MNGP ASME Code Class 1 Small-Bore Piping AMP is a new condition monitoring program for detecting cracking in small-bore, ASME Code Class 1 piping. This AMP augments the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program specified by ASME Code, Section XI, Sections IWB, IWC, and IWD, for certain ASME Code Class 1 piping that is less than 4 inches nominal pipe size (NPS) and greater than or equal to 1 inch NPS and manages the effects of SCC and cracking due to thermal or vibratory fatigue loading. This AMP inspects ASME Code Class 1 small-bore piping locations that are susceptible to cracking and inspects full penetration (butt) and partial penetration (socket) welds. This AMP also includes measures to verify that degradation is not occurring, thereby confirming that the aging effects are being managed effectively.

Industry OE demonstrates that welds in ASME Code Class 1 small-bore piping are susceptible to SCC and cracking due to thermal or vibratory fatigue loading. Such cracking is frequently initiated from the ID of the piping; therefore, volumetric examinations are needed to detect cracks. However, ASME Code, Section XI, generally does not call for volumetric examinations of this class and size of piping. Therefore, this AMP supplements the ASME Code Section XI examinations with volumetric examinations, or alternatively, destructive examinations, to detect cracks that may originate from the ID of butt welds, socket welds, and their base metal materials. The examination schedule and extent are based on plant-specific OE and whether actions have been implemented that would successfully mitigate the causes of past cracking.

A one-time inspection to detect cracking in welds and base metal materials will be performed by either volumetric or destructive examination. These inspections will provide assurance that aging-related cracking of small-bore ASME Code Class 1 piping is not occurring or is insignificant. Volumetric examinations will be performed on selected full penetration butt welds and partial penetration socket welds. Volumetric examinations must employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. Welds may be inspected via volumetric or destructive examination. Because more information can be obtained from a destructive examination than from nondestructive examination, credit will be taken for each socket weld destructively examined equivalent to having volumetrically examined two welds.

NUREG-2191, Table XI.M35-1, defines MNGP as a Category A plant because it has no history of age-related cracking. Per Category A, the inspection will be a one-time inspection with a sample size of 3 percent, up to a maximum of 10 welds, of each weld type, using a methodology to select the most susceptible and risk-significant welds.

Weld Type	Total Number	3%	Sample Size (Max 10 Welds Each Type)
Socket	>334	10	10
Full Penetration Butt	47	2	2

Based on the results of these inspections, the need for additional inspections or programmatic corrective actions will be established.

If a component containing flaws or relevant conditions is accepted for continued service by analytical evaluation, then it is subsequently reexamined to meet the intent of ASME Code, Section XI, Subarticle IWB-2420. Examination results are evaluated in accordance ASME Code, Section XI, Paragraph IWB-3132. The corrective actions include examinations of additional ASME Code Class 1 small-bore piping welds to meet the intent of ASME Code, Section XI, Subarticle IWB-2430. If any new OE or evaluation of the one-time examinations detect unacceptable flaws or relevant conditions, additional or periodic examinations would be implemented in accordance with Category B or C of Table XI.M35-1.

NUREG-2191 Consistency

The MNGP ASME Code Class 1 Small-Bore Piping AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.M35, *ASME Code Class 1 Small-Bore Piping*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

In February of 2020, MNGP prepared a proactive OE search on ISI related industry OE from 1/1/2017-2/14/2020. In the results from this search, no Class 1 small-bore piping findings were identified.

Since any cracking or leakage from Class 1 RCPB components would be required to be reported to the NRC per 10 CFR 50.73(a)(2), a review of some relevant License Event Reports (LERs) was performed for piping within the scope of the MNGP ASME Code Class 1 Small-Bore Piping AMP.

- **Hatch** (LER 05000366/2008-003-01): After finding leaks due to cracking of fillet welds, systems within the ASME Class 1 boundary were reviewed for lines which are small-bore, not isolable, and stainless steel. This cracking was determined to be caused from high cycle fatigue. Sixteen main steam flow connections on each Unit and the four flow measurement lines were selected to be evaluated and corrective actions taken as determined appropriate.

  By selecting samples that are the most susceptible for inspection, components can be identified through inspection results and corrected before component failure occurs due to the effects of aging.

- **Turkey Point** (LER 05000251/2008-003-00): Repair of a reactor coolant pump (RCP) test connection line after identifying a leak from a weld crack that likely started as a fabrication issue and was propagated from vibration and cycle fatigue.

  By selecting samples that are the most susceptible for inspection, components can be identified through inspection results and corrected before component failure occurs due to the effects of aging.

- **Browns Ferry** (LER 05000259/2008-002-01): An unisolable leak repair on an instrument line by weld overlay. Inservice examination requirements of the weld overlay were added to the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program. Remaining Unit small-bore instrument nozzle safe ends were ultrasonically examined with no further recordable indications.

  Since the indications described above were due to a fabrication issue and not related to thermal fatigue there was no impact on the MNGP AMP.

- **Susquehanna** (LER 05000387/2012-007-01): Modification and repair of a chemical decontamination connection of a recirculation pump suction line after under-estimated stress calculations during construction resulted in weld cracks due to cycle fatigue. Additional modifications, inspections, and corrective actions were planned to be taken.

  By selecting samples that are the most susceptible for inspection, components can be identified through inspection results and corrected before component failure occurs due to the effects of aging.

- **Hope Creek** (LER 05000354/2005-002-00): Modification and repair of recirculation loop connections after a weld crack was identified. Review of all other similar connections to the reactor recirculation loops was performed with all NDE inspection results found to be acceptable.

  Since the indications described above were due to a fabrication issue and not related to thermal fatigue there was no impact on the MNGP AMP.

- **Peach Bottom** (LER 05000278/2005-003-00): Replacement of a welded joint on an equalizing line for a RHR air-operated valve after a crack was identified. An extent of condition for similar welds on Unit 3 required additional repairs on both RHR loops.

Since the indications described above were due to a fabrication issue and not related to thermal fatigue there was no impact on the MNGP AMP.

- **Peach Bottom** (LER 05000278/2017-001-00): Replacement of a section of Class 1 small-bore piping and fitting instrument line on a recirculation pump. Instrument lines connected to the suction and discharge of both recirculation pumps with similar configuration and subject to vibration were also replaced during the next refueling outage. The new welds were performed with a 2:1 profile, which reduces susceptibility to vibration-induced failures.

  Since the indications described above were due to a fabrication issue and not related to thermal fatigue there was no impact on the MNGP AMP.

<u>Plant-Specific Operating Experience</u>

MNGP initial LR actions augmented the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program with one-time examinations of Class 1 small bore (2 inch through less than 4 inch) stainless steel butt welds. The sample included 10 stainless steel welds and 2 welds were examined each interval. After reviewing Owner's Activity Reports (OARs) from Cycles 27, 28, 29, and 30 that range from 2015 to present, no indications of aging were identified for any class 1 small-bore piping.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and one finding was identified related to the MNGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.3.1) AMP. With respect to Element 9 (Administrative Controls), the AMP document required update for information related to the Fifth 10-year Interval Plan, as well as some minor editorial changes. Completion of the required AMP document updates were tracked and documented. In addition, USAR Appendix K required a related update. The AMP effectiveness was not affected.

The MNGP ASME Code Class 1 Small-Bore Piping AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP ASME Code Class 1 Small-Bore Piping AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.23 External Surfaces Monitoring of Mechanical Components

The MNGP External Surfaces Monitoring of Mechanical Components AMP is an existing condition monitoring program, formerly the MNGP System Condition Monitoring Program, that manages loss of material, cracking, hardening or loss of strength (of elastomeric components), loss of preload for ducting closure bolting, reduction of heat transfer due to fouling (air to fluid heat exchangers), and reduction of thermal insulation resistance due to moisture intrusion. This AMP also inspects the integrity of coated surfaces as an effective method for managing the effects of corrosion on the metallic surfaces.

Visual inspections are performed during system inspections and walkdowns. The inspection parameters for metallic components include material condition, which consists of evidence of rust, general, pitting, and crevice corrosion; surface imperfections such as cracking and wastage, coating degradation such as cracking, flaking, or blistering; evidence of insulation damage or wetting, leakage, and accumulation of debris on heat exchanger surfaces. Coating degradation is used as an indicator of possible degradation on underlying surfaces of the component. Inspection parameters for elastomeric and polymeric components include hardening, discoloration, surface cracking, crazing, scuffing, loss of thickness, exposure of internal reinforcement, and dimensional changes. For certain materials, such as flexible polymers, manual and physical manipulation to detect hardening or loss of strength will be used to augment the visual inspections conducted under this program.

ASME Code inspections are conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings.

Non-stainless steel and non-aluminum components are inspected to detect age-related degradation at a frequency not to exceed one refueling cycle. This frequency accommodates inspections of components that may be in locations normally accessible only during refueling outages (e.g., high dose areas). Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

These visual inspections also inspect for external corrosion under insulation. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point) are also periodically inspected at a minimum of every 10 years during the SPEO. Sample inspections are conducted of each material type and environment where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Any combination of 1-foot length sections and components can be used to meet the recommended extent of 20 percent of the population of materials and environment combinations, with a maximum of 25 inspections required in each population. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. 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.

Alternative methods for detecting moisture/corrosion inside piping insulation (such as thermography, neutron backscatter devices, and moisture meters) will be used for inspecting piping jacketing that is not installed in accordance with plant-specific procedures (such as no minimum overlap, wrong location of seams, etc.).

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the SPEO, whichever is sooner. Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions. The MNGP External Surfaces Monitoring of Mechanical Components AMP also visually inspects the external surfaces of heat exchanger surfaces exposed to air (e.g., ventilation heat exchanger fins) for evidence of reduction of heat transfer due to fouling.

For situations where the internal (inaccessible) and external (accessible) surface environments are similar, such that the external (accessible) surface condition is representative of the internal (inaccessible) surface condition, then visual inspection of the accessible surfaces/components are performed. The MNGP External Surfaces Monitoring of Mechanical Components AMP procedures provide the basis to establish that the external and internal surface condition and environment are sufficiently similar. These inspections provide reasonable assurance that the following effects are managed:

a. Loss of material/cracking of internal surfaces for metallic components.

b. Loss of material/cracking of internal surfaces for polymeric components.

c. Hardening or loss of strength of internal surfaces for elastomeric components.

Depending on the material, components may be coated to mitigate corrosion by protecting the external surface of the component from environmental exposure. Inspections to verify the integrity of the insulation jacketing are performed per site procedures.

The MNGP External Surfaces Monitoring of Mechanical Components AMP procedures define acceptance criteria that are utilized during inspection walkdowns to identify deficiencies in the in-scope component groups. MNGP External Surfaces Monitoring of Mechanical Components AMP procedures require corrective actions be initiated for deficiencies identified during the walkdowns to ensure that loss of component intended functions does not occur. The MNGP External Surfaces Monitoring of Mechanical Components AMP procedures utilize guidance from the EPRI Technical Reports TR-1007933, *Aging Assessment Field Guide*, TR-1009743, *Aging Identification and Assessment Checklists, Mechanical Components*, TR-1011223, *Aging Identification and Assessment Checklists, Electrical Components*, and TR-1011224, *Aging Identification and Assessment Checklists, Civil and Structural Components*, for identifying degraded conditions. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection and the degradation is a valid indication or trend, then an AR is issued to perform an assessment and document the appropriate actions and recommendations, which may include the adjustment of inspection frequencies. When an AR is generated, the associated corrective action is documented in accordance with the MNGP CAP and the ARs require the determination of probable cause and actions to prevent recurrence for significant conditions adverse to quality.

NUREG-2191 Consistency

The MNGP External Surfaces Monitoring of Mechanical Components AMP, with enhancements, is consistent without exception to the ten elements of NUREG-2191, Section XI.M36, *External Surfaces Monitoring of Mechanical Components*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP External Surfaces Monitoring of Mechanical Components AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	• Revise procedure(s) to inspect heat exchanger surfaces exposed to air for evidence of reduction of heat transfer due to fouling. • Revise procedures to ensure areas that are frequently wetted are inspected. • Specify in procedure(s) that situations where the similarity of the internal and external environments are such that the external surface condition is representative of the internal surface condition, external inspections of components may be credited for managing: o loss of material and cracking of internal surfaces for metallic components, o loss of material, and cracking of internal surfaces for polymeric components, and

Element Affected	Enhancement
	○ hardening or loss of strength of internal surfaces for elastomeric components. ○ When credited, the program provides the basis to establish that the external and internal surface condition and environment are sufficiently similar.
3. Parameters Monitored or Inspected	• Revise procedure(s) to add the following inspection parameters for metallic components: ○ Corrosion stains on thermal insulation ○ Blistering of protective coating ○ Accumulation of debris on heat exchanger tube surfaces and air-side heat exchanger surfaces. • Revise procedure(s) to include inspection for elastomeric and polymeric components and its methodology. Elastomeric and flexible polymeric components are monitored through a combination of visual inspection and manual or physical manipulation of the material. Visual inspections cover 100 percent of accessible component surfaces. Manual or physical manipulation of the material includes touching, pressing on, flexing, bending, or otherwise manually interacting with the material in order to reveal changes in material properties, such as hardness, and to make the visual examination process more effective in identifying aging effects such as cracking. Flexing of polyvinyl chloride piping exposed directly to sunlight (i.e., not located in a structure restricting access to sunlight such as manholes, enclosures, and vaults or isolated from the environment by coatings) is conducted to detect potential reduction in impact strength as indicated by a crackling sound or surface cracks when flexed. The sample size for manipulation is at least 10 percent of available surface area. The inspection parameters for elastomers and polymers shall include the following: ○ Surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”) ○ Loss of thickness ○ Exposure of internal reinforcement for reinforced elastomers

Element Affected	Enhancement
	○ Hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation
4. Detection of Aging Effects	• Revise procedure(s) to specify that inspections are to be performed by personnel qualified in accordance with site procedures and programs to perform the specified task, and when required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), inspections are conducted in accordance with the applicable code requirements. • Revise procedure(s) to ensure non-ASME Code inspections and tests include inspection parameters for items such as lighting, distance offset, surface coverage, and presence of protective coatings. Surfaces that are not readily visible during plant operations and refueling outages should be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. • Revise procedure(s) to specify that, when inspecting to manage cracking of a component's material, either surface examinations conducted in accordance with plant-specific procedures or ASME Code Section XI VT-1 inspections (including those inspections conducted on non-ASME Code components) are conducted on each component inspected. An inspection requires that at least 20 percent of the surface area of the component is inspected, unless the component is measured in linear feet, such as piping. Any combination of 1-foot length sections and components can be used to meet the recommended extent of 20 percent of the population of materials and environment combinations, with a maximum of 25 inspections required in each population. 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. • Revise procedure(s) to specify alternative methods for detecting moisture inside piping insulation (such as thermography, neutron backscatter devices, and moisture meters) to be used for inspecting piping jacketing that is not installed in accordance with plant-specific procedures (such as no minimum overlap, wrong location of seams, etc.).

Element Affected	Enhancement
	• Revise procedure(s) to include the following information: ○ Component surfaces that are insulated and exposed to condensation (because the in-scope component is operated below the dew point), and insulated outdoor components, are periodically inspected every 10 years during the SPEO. ○ For all outdoor components and any indoor components exposed to condensation (because the in-scope component is operated below the dew point), inspections are conducted of each material type (e.g., steel, SS, copper alloy, aluminum) and environment (e.g., air outdoor, air accompanied by leakage) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator, tank) is inspected after the insulation is removed. Alternatively, any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. • Revise procedures to specify that: ○ Visual inspection will identify direct indicators of loss of material due to wear to include dimension change, scuffing, and, for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. ○ Visual inspection of elastomers and flexible polymers will identify indirect indicators of elastomer and flexible polymer hardening or loss of strength, including the presence of surface cracking, crazing, discoloration, and, for elastomers with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal.

Element Affected	Enhancement
	○ Visual inspections will cover 100 percent of accessible component surfaces. ○ Manual or physical manipulation can be used to augment visual inspection to confirm the absence of hardening or loss of strength for elastomers and flexible polymeric materials (e.g., heating, ventilation, and air conditioning flexible connectors) where appropriate, and the sample size for manipulation is at least 10 percent of available surface area.
5. Monitoring and Trending	• Revise procedure(s) to formalize sampling-based inspections. The results of sampling-based inspections will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain intended functions of the components throughout the SPEO based on the projected rate and extent of degradation.
6. Acceptance Criteria	• Revise procedure(s) to add an evaluation to project the degree of observed degradation to the end of the SPEO or the next scheduled inspection, whichever is shorter. • Revise procedure(s) to specify, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness, percent shrinkage allowed in an elastomeric seal). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. Where qualitative acceptance criteria are used, the criteria are clear enough to reasonably ensure that a singular decision is derived based on the observed condition of the systems, structures, and components (e.g., cracks are absent in rigid polymers, the flexibility of an elastomeric sealant is sufficient to ensure that it will properly adhere to surface).
7. Corrective Actions	• Revise procedure(s) to specify that if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the CAP.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. External surface inspections through system inspections and walkdowns have been in effect at many utilities since the mid-1990s in support of the Maintenance Rule (10 CFR 50.65) and have proven effective in maintaining the material condition of plant systems. The elements that comprise these inspections are consistent with industry practice.

The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the NUREG-2191 Appendix B.

- In Dominion's response to Surry SLRA RAI B2.1.23-1 (Reference ML19204A357), Dominion clarified that extensive corrective actions in the tunnel between the Turbine and Auxiliary buildings were effective in improving both access within the tunnel and the adverse external environment. The issues described in this RAI response were primarily driven by excessive moisture conditions existing in this area.

  The MNGP External Surfaces Monitoring of Mechanical Components AMP will be enhanced to ensure procedures are updated to emphasize the importance of inspecting areas that are frequently wetted.

- NRC IN 2012-19 summarizes several findings that were identified during post-approval site inspections, including the need for licensees to manage changes to NRC commitments and AMPs incorporated into the USAR supplements.

  MNGP addressed this information in their CAP by recommending action to each of the site's aging management coordinators. This IN was determined to not directly apply to MNGP because the IP-71003 inspection for MNGP was completed in July 2010 with no outstanding or follow-up issues. Specific items discussed in this IN were reviewed for possible application. These were either addressed during the LRA project or were completed during the implementation phase prior to entering the PEO. There were no additional IP-71003 inspections expected based on industry experience of plants that have entered the PEO.

Plant-Specific Operating Experience

A review of plant OE indicates that the MNGP External Surfaces Monitoring of Mechanical Components AMP is robust and that numerous work orders, condition reports/ARs have been issued as a result of or to evaluate evidence of aging mechanisms for external surfaces monitoring of mechanical components.

Action Requests

- An AR from May 2015 identified corrosion on a condensate system service pipe. Condensation from a valve above this pipe location was dripping onto the pipe. Although there was no current leak present, the wet and dry environment could have potentially resulted in loss of material due to corrosion over time. Actions were taken to visually inspect and examine by UT to determine any loss of material that would challenge the intended function of this component. A visual inspection was performed of the piping with pitting depth measurements taken. The deepest pitting was less than 1/32-in deep. The piping was evaluated as acceptable based on piping wall thickness >87.5 percent nominal thickness.

- An AR from April 2014 documented surface corrosion on a section of reactor building closed cooling water piping below a surge tank. This portion of the piping did not appear to be painted previously. Although the condition appeared to be minor surface corrosion, actions were recommended to clean and coat this portion of the piping. This condition was identified via system walkdown in support of aging management and evaluated by engineering. Based on a follow-up inspection of the area of concern, and input from the coating SME and industry experts, the condition appeared to be general surface corrosion from atmospheric conditions. No appreciable material loss had occurred. The piping was cleaned and coated per the work management process. The piping is monitored as part the system condition monitoring walkdowns.

- An AR from June 2016 documented leakage through cracks in the ceiling of the INS which resulted in the accumulation of chemicals on top of the fire header in this building. The chemicals were identified as a mixture of calcium and magnesium carbonate which comprises the matrix of concrete. Visual inspection determined there was no challenge to the integrity of the piping. Actions were taken to clean the affected area of the piping, provide more frequent cleaning of these areas, new coatings were placed on the roof and concrete repair work performed to stop the water intrusion.

- An AR from August 2016 documented results of a UT exam on the service water radiation monitor discharge piping. Areas of localized corrosion were detected in two sections of pipe reducing the wall thickness in these locations. All wall thickness measurements remained well above the minimum wall thickness values but below the administrative action limit and required piping replacement. The cause of the corrosion was microbiologically induced corrosion or under deposit corrosion (i.e., loss of material from the internal environment of the pipe). Work orders were issued to replace these sections of piping during the next maintenance window. Subsequent inspection of the piping in 2017 initiated actions to perform an alternate repair via pipe encapsulation to ensure the minimum wall thickness values would not be exceeded. This repair was implemented in November 2017.

  A review of the AR population from 2016-2020 shows other instances of identification of similar conditions for which corrective actions were taken.

This shows proactive identification of aging well before a loss of intended function.

Integrated Inspection Reports:

Integrated Inspection reports, which document NRC inspections findings, were reviewed from 2016-2021. During this period, none of the findings were related to the MNGP External Surfaces Monitoring of Mechanical Components AMP.

Effectiveness/Post-Approval Reviews:

2020 - License Renewal Effectiveness Review

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and no findings were identified related to the MNGP External Surfaces Monitoring of Mechanical Components AMP.

Focused Self-Assessments

2015 – System Condition Monitoring Assessment

An assessment of the system condition monitoring program was conducted. This AMP was evaluated as effective with no commitment vulnerabilities identified.

2016 – Aging Management Self-Assessment

The purpose of this self-assessment was in preparation for the 2016 NRC Problem Identification and Resolution (PIR) inspection. Based on a sample review of AMPs OE was determined to be properly incorporated.

2019 – License Renewal Phase IV Self-Assessment Plan

The purpose of this self-assessment was in preparation for the LR Phase IV NRC inspection. With respect to the MNGP External Surfaces Monitoring of Mechanical Components AMP, there were no specific findings or areas for improvement noted.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP External Surfaces Monitoring of Mechanical Components AMP.

The MNGP External Surfaces Monitoring of Mechanical Components AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP External Surfaces Monitoring of Mechanical Components AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is a new condition monitoring AMP that manages the aging effects of loss of material, cracking, reduction of heat transfer due to fouling, flow blockage, and hardening or loss of strength of elastomeric and polymeric materials. Some inspections and activities within the scope of the new AMP were previously performed by the MNGP Fleet Surveillance Test Program and MNGP Preventive Maintenance Program.

The MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to potentially aggressive environments. These environments include air, gas, condensation, diesel exhaust, any water-filled systems, fuel oil, and lubricating oil. Aging effects associated with items (except for elastomers and flexible polymeric components) within the scope of the MNGP Open-Cycle Cooling Water AMP (B.2.3.11), the MNGP Closed Treated Water Systems AMP (B.2.3.12), and the MNGP Fire Water System AMP (B.2.3.16) are not managed by this AMP.

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. In addition to these opportunistic inspections, specific components and systems that must be periodically inspected under this program are identified. The AMP includes visual inspections and when appropriate, surface examinations. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this AMP. At a minimum, in each 10-year period during the SPEO a representative sample of 20 percent of the population or a maximum of 25 components per population (defined as components having the same combination of material, environment, and aging effect) will be inspected for the in-scope aging effects.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Surface examinations or ASME Code Section XI VT-1 examinations will be conducted to detect cracking of SS and copper alloy (>15 percent Zn) components and opportunistic inspections will continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program. If visual inspection of internal surfaces is not possible, a plant-specific program will be used.

Internal visual inspections used to assess loss of material will be capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected for steel components exposed to raw water, raw water (potable), or wastewater, follow-up volumetric examinations will be performed.

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 will be such that the component will meet its intended function until the next inspection or the end of the SPEO. Qualitative acceptance criteria will be clear enough to reasonably assure a singular decision is derived based on observed conditions. Corrective actions will be performed as required based on the inspections results.

This AMP is also used to manage cracking due to SCC in copper alloy (>15 percent Zn) and stainless steel components exposed to aqueous solutions. There are no titanium components within the scope of this AMP. Internal coatings of tanks are not managed by this AMP. This AMP is not used to manage components where visual inspection of internal surfaces is not possible unless specific volumetric inspections are performed as noted above.

For loss of material due to recurring internal corrosion, the frequency and extent of wall thickness inspections will be increased commensurate with the significance of the degradation. If the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement 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 inspections will be increased in accordance with the MNGP CAP; however, no fewer than five additional inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less.

NUREG-2191 Consistency

The MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M38, *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. The following examples describe OE pertaining to inspections of internal surfaces of miscellaneous piping and ducting components within the scope of this program:

- Inspections of internal surfaces during the performance of periodic surveillance and maintenance activities have been in effect at many utilities in support of plant component reliability programs. These activities have proven effective in maintaining the material condition of plant SSCs. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. The applicant evaluates recent OE and provides objective evidence to support the conclusion that the effects of aging are adequately managed.

  The review of plant-specific OE during the development of this program is addressed below. The review was broad and detailed enough to detect instances of aging effects that have occurred repeatedly. Repeatedly occurring aging effects (i.e., recurring internal corrosion) meeting the criteria in SRP-SLR Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6, *Loss of Material due to Recurring Internal Corrosion*, include criteria to determine whether recurring internal corrosion is occurring, and recommendations related to augmenting aging management activities.

  The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

Plant-Specific Operating Experience

The following summary of plant-specific OE (which includes review of corrective actions and NRC inspections) provides examples of how MNGP is managing aging effects associated with the internal surfaces in miscellaneous piping and ducting components managed by the MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.

- In November 2012, MNGP documented corrosion and crud build-up in the discharge piping for the HPCI room air cooling unit. This condition was discovered during an activity to replace the cooling unit. An evaluation of the condition determined that the crud build-up was not age-related degradation and was limited to this portion of the piping. Ultrasonic analysis was conducted and conservatively determined that based on the calculated wear rate, minimum wall conditions would not be reached until after twenty-four years. The corroded portion of the discharge piping was replaced.

- In October 2014, corrosion of the end-bell partitions and tubesheet of a Control Room ventilation heat exchanger was identified. The end-bell partition corrosion was significant enough that end-bell replacement was recommended. Tubesheet corrosion had continued since the last inspection but the sealing surface and tube sheet integrity were not challenged. A work order to change out the end-bells was issued. The end-bells were replaced in 2014.

- An internal inspection of a RHRSW heat exchanger outlet isolation valve conducted in April 2015 documented that the valve had internal erosion around the valve disk. There was no significant erosion or material loss at the valve pressure boundary. The valve retained its ability to open (normal position), close and isolate the heat exchanger outlet. Since continued loss of material of the valve could prevent future isolations, a work order was generated. In 2021, the valve provided an isolation boundary. Valve seat leakage was determined to not be impacted by the condition identified and the repair work for the RHRSW heat exchanger outlet isolation valve was cancelled.

- In April 2016, excessive corrosion of the outside gasket sealing area of the RBC heat exchanger end-bell was identified. This condition was observed after cleaning the end bell in preparation for divider plate and end-bell repair. The corrosion of the divider gasket sealing area was repaired. The heat exchanger was cleaned every 3 years per site experience under the preventive maintenance procedure. During previous preventive maintenance of the heat exchanger, corrosion was identified on the divider plates and end bell. A work order was written to have both end bell gasket mating surfaces weld repaired which was subsequently scheduled with the performance of the PM procedure in 2016. When excessive corrosion was identified on the end-bell (outer sealing area and divider plate) during the current heat exchanger cleaning, planning, engineering, and maintenance determined that the end bells should be sent off to be machined and weld repaired. In addition, an equivalency evaluation was prepared to enable application of replacement epoxy coating to the heat exchanger end bells and divider plate to reduce future corrosion concerns (MIC resistant). The condition evaluation performed an extent of condition evaluation and determined that the PM frequency and addition of the epoxy coating was appropriate for continued management of the corrosion of the heat exchangers. The corrosion on the mating surface was repaired with epoxy coating applied during the 2016 maintenance opportunity.

- An inspection in June 2018 captured the results of an inspection of one of the RHR heat exchangers. Localized corrosion was noted in the waterbox that exceeded the corrosion allowance. There were several areas of localized thinning identified. A detailed structural analysis was performed and demonstrated that the heat exchanger met its code allowable stresses and would continue to meet the allowables until the next inspection. The current PM frequency to clean/eddy current test the RHR heat exchanger was set at 8 years. A condition evaluation was performed and concluded that based on the level of corrosion seen in this heat exchanger between the previous inspection and the 2018 inspection, the current PM frequency of every 8 years should be maintained. This conclusion was based on the heat exchanger being original equipment, a known rate of corrosion on the channel/cover, the consequence of a tube leak being river water leaking into the reactor water side, and industry OE and EPRI guidance. Weld repair of the divider plate and recoating of the corroded areas was performed to ensure the integrity of the heat exchanger until its next inspection.

- In August 2019, a potential leak path on the RCIC oil cooler heat exchanger and the CRD pump gear box lubricating oil coolers was identified by reviewing OE from another nuclear plant site. The leak path was associated with the location of the sacrificial zinc anode plugs on the coolant side of the coolers. Given the similarity of the design to MNGP, all critical heat exchangers were evaluated for the presence of these plugs. This design was found on the MNGP RCIC lubricating oil cooler and CRD pump gear box lubricating oil coolers. For the RCIC oil cooler heat exchanger an initial inspection was performed to confirm no leakage from the zinc anode plug weep hole and the RCIC PM procedure was revised to provide for periodic inspection and, if necessary, replacement of the zinc anode plug. For the CRD pump gear box lubricating oil coolers actions were initiated to replace the CRD gear box plugs under two work orders.

- In March 2021, an inspection of an internal FIR System piping was conducted. The inspection observed minor accumulation of loose corrosion byproducts in several locations. None of the observed conditions would have resulted in piping or sprinkler head blockage. These lines were flushed in September 2021.

Integrated Inspection Reports

Integrated Inspection reports, which document NRC inspections findings, were reviewed from 2016-2021. During this period, none of the findings were related to the scope of the MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. The second quarter 2019 Integrated Inspection Report (Reference ML19214A147) noted that the RCS boundary, reactor vessel internals, risk-significant piping system boundaries, and containment boundary are appropriately monitored for degradation and that repairs and replacements were appropriately fabricated, examined and accepted by reviewing a series of activities performed by MNGP.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.25 Lubricating Oil Analysis

The MNGP Lubricating Oil Analysis AMP is an existing sampling program that manages loss of material and reduction of heat transfer in components exposed to lubricating oil within the scope of SLR by maintaining the required oil quality to prevent or mitigate age-related degradation. The MNGP Lubricating Oil Analysis AMP maintains lubricating oil system contaminants such as water and particulates within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Testing activities include sampling and analysis of lubricating oil for contaminants which could be indicative of in-leakage and corrosion product buildup.

Verification of the effectiveness of the MNGP Lubricating Oil Analysis AMP will be conducted by the MNGP One-Time Inspection AMP (B.2.3.20) on selected components at susceptible locations in oil environments.

The MNGP Lubricating Oil Analysis AMP maintains oil system contaminants within acceptable limits and performs sampling for water, particle count, and other parameters to detect evidence of contamination by moisture or excessive corrosion. Water and particle concentration are not to exceed limits based on equipment manufacturer's recommendations or industry standards. Equipment with oil sample results exceeding parameter limits may be subjected to actions including, but not limited to resampling, increased sampling frequency, and additional monitoring and trending of select parameters.

NUREG-2191 Consistency

The MNGP Lubricating Oil Analysis AMP, with an enhancement, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M39, *Lubricating Oil Analysis*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Lubricating Oil Analysis AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
6. Acceptance Criteria	Revise procedure(s) and/or PM(s) to clarify that phase-separated water in any amount is not acceptable. If phase-separated water is identified in the sample, then corrective actions are to be initiated to identify the source and correct the issue (e.g., repair/replace component or modify operating conditions).

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. The industry OE identified includes (a) water in the lubricating oil and (b) particulate contamination.

Plant-Specific Operating Experience

- In March 2017, the lubricating oil analysis of a core spray motor showed increased water concentration above the alert limit (but below the alarm limit) provided in the lubrication plan procedure, and the finding was placed into CAP. The oil sample was slightly cloudy, and visible water droplets were present at the bottom of the oil sample. A backup sampling was performed to verify the findings, and the water concentration from the backup sample was consistent with previously trended level which was below the alert level. The backup sample was clear and bright without droplets of water present in the initial oil sample. Based on the information provided in the backup sample, there was a reasonable assurance that the motor would accomplish its intended function, and no further action was required.

- In November 2017, the lubricating oil samples from cooling tower gearboxes showed increased water concentration above the alert limit (but below the alarm limit) provided in the lubrication plan procedure, and the finding was placed into CAP. All other parameters were in the acceptable range. The elevated water level did not warrant immediate actions, and the water levels were lowered to below the target levels at the next available opportunities to ensure long term reliability of the components.

- In December 2017 and March 2018, the lubricating oil analyses of RHR pump motors indicated ferrous content above the desired range provided in the lubrication plan procedure, and the finding was placed into CAP. Other parameters were in the acceptable range, and no indication of mechanical or bearing defects were found. Since the increased ferrous levels were low with no other findings, the higher ferrous content in the lubricating oil for each motor was considered minor and would not affect long term operation of the pump.

- In April 2019, the lubricating oil analysis reports for the condensate upper motor indicated that some of the oil properties such as viscosity, and wear metals such as iron, aluminum and copper had increased. The finding was placed into CAP. The viscosity and all other lubricating oil properties were acceptable per established criteria in the lubrication plan procedure. However, this motor was required to run continuously for two years. Therefore, the lubricating oil was replaced during the next outage to ensure equipment reliability during the following cycle.

The MNGP Lubricating Oil Analysis AMP is an existing sampling program per existing activities. This AMP was not formalized for the initial LRA, and the effectiveness/self-assessment reviews were not performed for this AMP. AMP effectiveness will be assessed at least every five years per NEI 14-12.

The MNGP Lubricating Oil Analysis AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Lubricating Oil Analysis AMP, with an enhancement, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The MNGP Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is an existing condition monitoring program that periodically inspects and analyzes test coupons of the Boral material in the spent fuel storage racks to determine if the neutron-absorbing capability of the material has degraded over time. This program ensures that a 5 percent sub-criticality margin in the SFP is maintained during the SPEO by monitoring for loss of material, changes in dimension, and loss of neutron-absorption capacity of the Boral material.

The specific acceptance criteria for boron-10 areal density and boral coupon thickness measurements are used to determine degradation that would challenge the 5 percent sub-criticality margin. Failure to meet the established criteria results in the condition being entered in the CAP.

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP monitors changes in condition of the Boral material in the spent fuel storage racks through visual inspections, dimensional measurements, neutron-attenuation testing, and weight and specific gravity measurements of representative test coupons. The primary measurements used to characterize performance of the Boral coupons are dimensional measurements (to detect bulging or swelling) and neutron-attenuation testing (to confirm the boron-10 areal density). Results of each coupon surveillance are documented and retrievable for purposes of trending. Acceptance criteria thresholds are established as indicators of potential adverse trends in the condition of the Boral material to ensure corrective actions are taken prior to compromising the 5 percent sub-criticality margin as contained within the SFP criticality analysis.

The maximum interval between each inspection and between each coupon test is not to exceed 10 years, regardless of OE.

NUREG-2191 Consistency

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is consistent with the program described in NUREG-2191, Section XI.M40, *Monitoring of Neutron-Absorbing Materials Other Than Boraflex*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

Some of the industry OE related to the MNGP Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is discussed in IN 2009-26, Degradation of Neutron-Absorbing Materials in the Spent Fuel Pool, and listed below:

(1) Loss of material from the neutron-absorbing material has been seen at many plants, including loss of aluminum, which was detected by monitoring the aluminum concentration in the spent fuel pool. One instance of this was documented in the Vogtle LRA Water Chemistry Program.

(2) Blistering has also been noted at many plants. Examples include blistering at Seabrook and Beaver Valley.

(3) The significant loss of neutron-absorbing capacity of the plate-type carborundum material was reported at Palisades.

(4) The coupon testing program at Kewaunee observed loss of boron-10 areal density of Tetrabor.

(5) The coupon testing programs at Calvert Cliffs Unit 1 and Crystal River Unit 3 observed weight loss of sheet-type Carborundum.

The MNGP Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP is capable of detecting the applicable aging mechanisms noted above. The program is informed and enhanced when necessary, through the systematic and ongoing review of both plant-specific and industry OE including research and development such that the effectiveness of the AMP is evaluated consistent with the discussion in Appendix B of the GALL-SLR Report.

Plant-Specific Operating Experience

Prior to the last coupon test in 2015, coupon evaluations have not identified any aging effects that could affect rack integrity or neutron absorption characteristics. The most recent coupon evaluation determined the average thickness of coupons 7A, 7B, and 7C were all below the TS limit. All coupons are expected to remain below the TS limit for at least 165 years, which is much longer than the maximum 10-year testing interval described in TS 5.5.14.

The minimum measured boron areal densities for coupons 7A, 7B, and 7C were all above the TS required value. The boron areal density is expected to be above the TS required value for at least 57 years for coupons 7A and 7C, which is much longer than the maximum 10-year testing interval described in TS 5.5.14.

All test results meet TS 5.5.14 requirements. The 10-year test interval specified in TS 5.5.14 is acceptable for all coupons until 2025, at which point another test will be performed and a new trend will be established based on the test results from the test performed in 2015.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, but the previous Spent Fuel Pool Boral Monitoring Program was not assessed during this review since this program is not a credited license renewal AMP as it is currently only a TS requirement.

Conclusion

The MNGP Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.27 Buried and Underground Piping and Tanks

The MNGP Buried and Underground Piping and Tanks AMP, previously known as the Buried Piping and Tanks Inspection Program, is an existing condition monitoring program that manages the aging effects associated with the external surfaces of buried and underground piping and tanks such as loss of material and cracking. This program addresses piping and tanks composed of metallic (steel and stainless steel) materials that are within the scope of SLR in the Condensate Storage, DGN, ESW, Fire Water, Off-Gas, SCT, Service and Seal Water, and Wells and Domestic Water Systems. There are no polymeric, cementitious, or metallic materials other than those metals previously stated for the in-scope systems, therefore, the aging management of these materials is not applicable.

This AMP manages aging through preventive, mitigative, inspection and performance monitoring activities. The MNGP Buried and Underground Piping and Tanks AMP includes (a) preventive actions to mitigate degradation (e.g., external coatings or wrappings, cathodic protection and quality of backfill), (b) condition monitoring (inspections) (e.g., verification of cathodic protection effectiveness, nondestructive evaluation of pipe or tank wall thicknesses, and visual inspections of the external surfaces and coatings/wraps of pipe or tanks, and internal tank inspections capable of detecting loss of material on the external surface), and (c) performance monitoring activities (e.g., pressure testing of piping, performance monitoring of fire mains) to provide early warning of system leakage. The locations of these inspections will be based on plant OE and opportunities for inspection such as scheduled maintenance work. These inspections will occur once prior to the SPEO and at least every 10 years during the SPEO. If an opportunity for inspection on non-leaking piping occurs prior to the scheduled inspection, the opportunistic inspection can be credited for satisfying the scheduled inspection.

The MNGP Buried and Underground Piping and Tanks AMP manages applicable aging effects such as loss of material and cracking. Depending on the material and environment, preventive actions may include using external coatings, cathodic protection, and quality backfill; inspection activities may include verification of the effectiveness of cathodic protection, nondestructive evaluation of pipe or tank wall thicknesses, pressure testing of the pipe, performance monitoring of fire mains, and visual inspections of the pipe or tank from the exterior, and internal tank inspections capable of detecting loss of material on the external surface.

The only tank within the scope of this AMP is the diesel fuel oil storage tank (bitumastic coated carbon steel tank).

Soil samples taken from domestic water and monitoring wells show that the soil conditions around MNGP are very mild, while plant OE has shown that there is not one area more susceptible to corrosion than any other. Previous inspections of buried and underground piping and tanks also indicate a non-aggressive soil environment; there are no pipes categorized as needing a repair or replacement schedule.

The most recent annual cathodic protection system survey performed in 2021 determined that not all of the surveyed locations met the -850 mV polarized potential criterion for buried steel components. The survey also determined that not all of the surveyed locations met the 100 mV polarization criterion. Therefore, the cathodic protection system does not currently meet the acceptance criteria of NACE SP0169-2007 or NACE RP0285-2002 and is not credited as a preventive measure at MNGP.

SCC of steel piping can occur in steel piping exposed to a carbonate and/or bicarbonate environment. Soil sample results from MNGP have shown the presence of carbonate and/or bicarbonate in certain locations and non-detectable in other locations. Figure 2 of NACE SP0169-2007 indicates the susceptibly of buried steel to SCC is based on temperature and polarized potential of the cathodic protection system. Exposure of steel to this environment also requires a degraded coating, and since steel piping at MNGP is coated in accordance with plant procedures, and plant-specific OE indicates that buried coatings have shown little degradation; this exposure is not expected. Based on soil temperature at the site and good OE with coatings of buried piping, SCC of steel piping is not expected but is conservatively assumed to be applicable at MNGP and will therefore be managed by this AMP.

The number of inspections for each 10-year inspection period, commencing 10 years prior to the start of SPEO, are based on the inspection quantities noted in NUREG-2191, Table XI.M41-2 for Category F. However, changes in plant-specific conditions can result in transitioning to a different number of inspections than originally planned at the beginning of a 10-year period. For example, refurbishment of the cathodic protection system to meet NACE acceptance criteria could result in transitioning to a lower Category from Preventive Action Category F

Material	No. of Inspections	Notes
Steel piping (buried)	6 inspections	The smaller of 10% of the piping length or 6 inspections.
Steel piping (underground)	2 inspections	The smaller of 2% of the piping length or 2 inspections.
Stainless steel piping (buried)	1 inspection	None
Stainless steel piping (underground)	1 inspection	None
Steel tank (buried)	1 inspection	Only one tank is buried at MNGP. If the diesel fuel oil storage tank is properly cathodically protected with a refurbishment to the system in the future, no inspections would be required per NUREG-2191 XI.M41 Section 4.b.vii.

This AMP does not provide aging management of selective leaching. The MNGP Selective Leaching of Materials AMP (B.2.3.21) is applied in addition to this program for applicable materials and environments.

NUREG-2191 Consistency

The MNGP Buried and Underground Piping and Tanks AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M41, *Buried and Underground Piping and Tanks*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Buried and Underground Piping and Tanks AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Update MNGP BUPT AMP procedures as appropriate: • State that new and replacement backfill shall meet the requirements of NACE SP0169-2007 Section 5.2.3 or NACE RP0285-2002 Section 3.6.
3. Parameters Monitored or Inspected	Update MNGP BUPT AMP procedures as appropriate: • Clarify when a volumetric examination should be performed and clarify when pit depth gages or calipers may be used for measuring wall thickness. These techniques may be used as long as: (a) they have been determined to be effective for the material, environment, and conditions (e.g., remote methods) during the examination; and (b) they are capable of quantifying general wall thickness and the depth of pits. • Perform visual inspection of external surfaces of controlled low strength material backfill, where such material is used, to detect potential cracks that could admit groundwater to the surface of the component. • Clarify that inspections for cracking due to stress corrosion cracking for stainless steel and steel (in a carbonate-bicarbonate environment) utilize a method that has been determined to be capable of detecting cracking.

Element Affected	Enhancement
	Coatings that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate do not have to be removed. Inspections for cracking are conducted to assess the impact of cracks on the pressure boundary function of the component.
4. Detection of Aging Effects	Update MNGP BUPT AMP procedures as appropriate: • Clarify that inspections of buried and underground piping and tanks within the applicable plant systems will be conducted in accordance with NUREG-2191 Table XI.M41-2 Preventive Action Category F for buried steel and stainless steel piping, unless a reevaluation of cathodic protection performance, future OE, or soil conditions determines that another Preventive Action Category is more applicable. When the inspections for a given material type is based on percentage of length and results in an inspection quantity of less than 10 feet, then 10 feet of piping is inspected. If the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping is inspected. • Clarify that the visual inspections will be supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed. • Clarify the guidance for piping inspection location selection as follows: (a) a risk ranking system software incorporates inputs that include coating type, coating condition, cathodic protection efficacy, backfill characteristics, soil resistivity, pipe contents, and pipe function; (b) opportunistic examinations of nonleaking pipes may be credited toward examinations if the location selection criteria are met; and (c) the use of guided wave ultrasonic examinations may not be substituted for the required inspections.
5. Monitoring and Trending	Update MNGP BUPT AMP procedures as appropriate: • Specify that degradation (e.g., coating condition, wall thinning) is projected, where practical, until the next scheduled inspection. Results are evaluated against

Element Affected	Enhancement
	acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation.
6. Acceptance Criteria	Update MNGP BUPT AMP procedures as appropriate: • For coated piping or tanks, there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as insignificant by an individual: (a) possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (b) who has completed the Electric Power Research Institute Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (c) a coatings specialist qualified in accordance with an ASTM standard endorsed in RG 1.54, Revision 2, *Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants*. • Specify that degradation (e.g., coating condition, wall thickness) is projected until the next scheduled inspection. Results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the SPEO based on the projected rate and extent of degradation. • Indications of cracking in metallic pipe are managed in accordance with the CAP. • Backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the component's coatings or the surface of the component (if not coated). • For pressure tests, the test acceptance criteria are that there are no visible indications of leakage, and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or by quantified leakage across test boundary valves. • Cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable.

Element Affected	Enhancement
7. Corrective Actions	Update MNGP BUPT AMP procedures as appropriate: • Where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill, an extent of condition evaluation is conducted to determine the extent of degraded backfill in the vicinity of the observed damage. • Evaluate the coated and uncoated metallic piping and tanks that show evidence of corrosion to ensure that the minimum wall thickness is maintained throughout the SPEO. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the SPEO meets minimum wall thickness requirements, the NUREG-2191 Section XI.M41 recommendations for expansion of sample size do not apply. • Where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition is repaired, or the affected component is replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the SPEO, an expansion of sample size is conducted. The number of inspections within the affected piping categories are doubled or increased by five, whichever is smaller. If the acceptance criteria are not met in any of the expanded samples, an analysis is conducted to determine the extent of condition and extent of cause. The number of follow-on inspections is determined based on the extent of condition and extent of cause. The timing of the additional examinations is based on the severity of the degradation identified and is commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection is completed within the 10-year interval in which the original inspection was conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval. These additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited towards the required number of inspections for the following 10-year interval. The number of inspections may be limited by the

Element Affected	Enhancement
	extent of piping or tanks subject to the observed degradation mechanism.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

Industry OE shows that buried and underground piping and tanks are subject to corrosion. The critical areas appear to be at the interface where the component transitions from above ground to below ground. This is also the area where coatings and wrappings will most likely be missing or damaged. Corrosion of buried oil, gas, and hazardous materials pipelines have been adequately managed through a combination of inspections and mitigative techniques, such as those prescribed in NACE SP0169-2007 and NACE RP0285-2002. The following industry OE is identified in NUREG-2191:

a. In August 2009, a leak was discovered in a portion of buried aluminum pipe where it passed through a concrete wall. The piping was in the condensate transfer system. The failure was caused by vibration of the pipe within its steel support system. This vibration led to coating failure and eventual galvanic corrosion between the aluminum pipe and the steel supports (Reference ML093160004).

b. In June 2009, an active leak was discovered in buried piping associated with the condensate storage tank. The leak was discovered because elevated levels of tritium were detected. The cause of the through-wall leaks was determined to be the degradation of the protective moisture barrier wrap that allowed moisture to come in contact with the piping resulting in external corrosion.

c. In April 2010, while performing inspections as part of its buried pipe program, a licensee discovered that major portions of their auxiliary feedwater piping were substantially corroded. The licensee’s cause determination attributed the corrosion to the failure to properly coat the piping “as specified” during original construction. The affected piping was replaced during the next refueling outage (Reference ML103000405).

d. In November 2013, minor weepage was noted in a 10-inch service water supply line to the EDGs while performing a modification to a main transformer moat. Coating degradation was noted at approximately 10 locations along the exposed piping. The leaking and unacceptable portions of the degraded pipe were clamped and recoated until a permanent replacement could be implemented (Reference ML13329A422).

Plant-Specific Operating Experience

- In February 2010, the cathodic protection test station was not connected to any buried piping. The structure lead was disconnected in the early 1980s; however, it is unknown how it was disconnected. This was discovered during the pre-operational test for the new Cathodic Protection System. This disconnected structure lead had no adverse effect on the functionality of the Cathodic Protection System. No further action was required since an equivalent measurement was able to be obtained to monitor the protection level in this area. This example demonstrates that surveys/tests are capable of detecting issues with the level of protection provided by the Cathodic Protection System. This item was entered into the CAP.

- In July 2010, during excavation for work near the security gatehouse, a drainage pipe was uncovered. This piping was not in scope of SLR, but per NRC commitment MO5013A and QF-1306, if buried piping was uncovered during excavation the buried piping program owner was to be notified and allowed to perform a visual inspection prior to the pipe being filled or recovered. Before the program owner was notified and allowed to perform a visual inspection, the drainage pipe was covered and prepared to be filled with concrete. The excavation permit and excavation procedures were not properly followed; both documents required that the pipe be visually inspected prior to being covered. Construction craft personnel contacted the buried piping program owner; however, the buried piping was no longer exposed and could not be visually inspected. The piping would be exposed at the same location during the next phase of the excavation activity that was scheduled to start the next working day. The site reinforced the requirement to following the instructions of excavation procedures and permits. This example demonstrates that deficiencies are entered into the CAP and action are taken to resolve deficiencies. This item was entered into the CAP.

- In May 2013, coating inspection of the CST buried piping revealed coating failures. Exposed stainless steel piping showed no signs of degradation. However, heat trace components were degraded from exposure to the surrounding soil. The heat trace lines were run through standard piping conduit that was banded to the condensate pipe prior to coating the pipe with coal tar wrap and then insulated before it was backfilled. This method of installation would allow new heat trace lines to be pulled through the conduit if needed. The air gap produced in the protective coating adjacent to the conduit was not filled by the coal tar wrap or by the tar that was applied after the wrap. This area was the point of coating failures that allowed ground water and backfill material access to the conduit and piping surface.

  New conduit was installed in areas where the heat trace was not in contact with the pipe, in soil and through the concrete floor. The remainder of the heat trace cable was placed against the pipe and then covered by the protective coal tar wrap. Continuity tests were performed prior to recoating the piping to validate that there were no faults in the cable. This example demonstrates that identified issues are entered into the CAP and action are taken to resolve deficiencies.

- In April 2015, based on trending of groundwater samples, the ground water/soil conditions indicated a potential adverse environment to buried components. Annual chloride concentration samples had been increasing from 2011 to 2015. Both the Buried Piping and Tanks Inspection AMP and the Structures Monitoring AMP take credit for benign ground water/soil conditions. NRC Commitment M05048A requires sampling of ground water for pH, chloride concentration, and sulfate concentration. There was no indication of a loss of component or structures intended function. The increase in chloride concentration was likely due to salt treatment during the winter months. To prevent an increase in chloride concentrations, the station would have had to cease use of salt to prevent ice conditions on walking surfaces which would constitute a safety concern for the station.

  Since the chloride concentration limit had not been exceeded, actions to prevent an increase in chlorides or mitigate the concern were not recommended. The station increased the sampling frequency to monthly (for pH, chloride, sulfate) to improve trending. No additional corrective actions were identified for this issue. This example demonstrates that trending of program parameters is capable of identifying issues, and feedback is used to make enhancements to program management. This item was entered into the CAP.

- In December 2019, an OE evaluation was performed for MNGPs Cathodic Protection System. The original Cathodic Protection System was installed during site construction. That system was designed to provide a -100 mV polarization protection for the buried pipes and tanks and was consistently operated and maintained by the performance of periodic surveys. At the commencement of license renewal preparation activities, the original Cathodic Protection System had reached the end of its effective life. The LRA and existing Buried Piping and Tanks Inspection program were approved without crediting the Cathodic Protection System as a preventive measure. Degrading system performance prompted MNGP to repair and upgrade the system in 2010 to ensure adequate corrosion protection of MNGP buried assets. This example demonstrates that systematic and ongoing review of both plant-specific and industry OE is capable of informing the program of shortfalls and developing strategies to resolve identified issues.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and no findings were identified related to the MNGP BUPT AMP. The effectiveness review also identified the significant enhancements for the BUPT AMP to be brought into compliance with NUREG-2191.

The MNGP BUPT AMP will be informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Buried and Underground Piping and Tanks AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be a new condition monitoring AMP that will have the principal objective to manage the aging effect of loss of coating/lining integrity.

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be a condition monitoring program that will manage degradation of internal coatings/linings exposed to raw water, treated water, and waste water that can lead to loss of material of base materials or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will not be used to manage loss of coating integrity for external coatings. There are no internal coatings that require management by this program in a CCCW, condensation, air, or oil environment at MNGP. The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP performs inspections of coatings/linings applied to components which are managed by the MNGP Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.3.17) AMP, the MNGP Open-Cycle Cooling Water (B.2.3.11) AMP, MNGP Fire Water System (B.2.3.16) AMP, MNGP Water Chemistry (B.2.3.2) AMP, MNGP One-Time Inspection (B.2.3.20) AMP, and the MNGP Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24) AMP.

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will manage these aging effects for internal coatings by conducting opportunistic and periodic visual inspections of coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component's or a downstream component's CLB intended function(s). Where visual inspection of the coated/lined internal surfaces determines the coating/lining is deficient or degraded, physical tests will be performed, where physically possible, in conjunction with the visual inspection. The MNGP AMP will use the following acceptance criteria:

- There are no indications of peeling or delamination.
- Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are completely surrounded by sound coating/lining bonded to the substrate. Blister size or frequency should not be increasing between inspections (e.g., ASTM D714-02, *Standard Test Method for Evaluating Degree of Blistering of Paints*) (Reference 1.6.50).
- Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff limitations associated with use of a particular standard.

- Minor cracking and spalling of cementitious coatings/linings is acceptable provided there is no evidence that the coating/lining is debonding from the base material.

- As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

- Adhesion testing results, when conducted, meet, or exceed the degree of adhesion recommended in plant-specific design requirements specific to the coating/lining and substrate.

For tanks and heat exchangers, all accessible surfaces will be inspected. Piping inspections will be sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings will be conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. For cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience. Peeling and delamination will not be acceptable. Blisters will be evaluated by a coatings specialist to confirm the surrounding material is sound and the blister size and frequency is not increasing. Minor cracks in cementitious coatings will be acceptable provided there is no evidence of debonding. All other degraded conditions will be evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. Additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment.

Opportunistic inspections, in lieu of periodic inspections, will be performed for the buried concrete lined fire protection piping. MNGP will perform flow tests and internal piping inspections at intervals specified by NUREG-2191, Table XI.M27-1, and will be capable of detecting through-wall flaws in the piping through continuous system pressure monitoring (alarm setpoints). Plant specific OE will be utilized to identify the need for tests and inspections to satisfy this requirement.

If inspection intervals are established by the CAP that are more frequent than those in Table XI.M42-1 of NUREG-2191, then those inspections will not be changed to a less frequent interval at the time of entry into the SPEO unless the requirements to change to Inspection Category A have been met (see note 5 of Table XI.M42-1 of NUREG-2191).

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will have a new governing and inspection procedure(s) consistent with NUREG-2191, Section XI.M42, as modified by SLR-ISG-2021-02-MECHANICAL. Existing procedures that supplement the governing procedure are also required to be updated to ensure that the inspection frequency and sampling criteria are followed, and that in-scope internal coatings are captured.

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP implementation and pre-SPEO inspections will be completed no later than 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO. The pre-SPEO baseline inspections will start no earlier than 10 years prior to the SPEO.

NUREG-2191 Consistency

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.M42, *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* as modified by SLR-ISG-2021-02-MECHANICAL.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

MNGP evaluates industry OE items for applicability per the MNGP OE program and takes appropriate corrective actions. The following examples describe OE pertaining to loss of coating or lining integrity for coatings/linings installed on the internal surfaces of system components within the scope of this program:

- In 1982, a licensee experienced degradation of internal coatings in its spray pond piping system. This issue contains many key aspects related to coating degradation. These include installation details such as improper curing time, restricted availability of air flow leading to improper curing, installation layers that were too thick, and improper surface preparation (e.g., oils on surface, surface too smooth). The aging mechanisms included severe blistering, moisture entrapment between layers of the coating, delamination, peeling, and widespread rusting. The failure to install the coatings to manufacturer recommendations resulted in flow restrictions to the ultimate heat sink and blockage of an EDG governor oil cooler. (IN 85-24, *Failures of Protective Coatings in Pipes and Heat Exchangers*. (Reference ML031180373))

- During an NRC inspection, the staff found that coating degradation, which occurred as a result of weakening of the adhesive bond of the coating to the base metal due to turbulent flow, resulted in the coating eroding away and leaving the base metal subject to wall thinning and leakage. (Reference ML12045A544).

- In 1994, a licensee replaced a portion of its cement lined steel service water piping with piping lined with polyvinyl chloride material. The manufacturer stated that the lining material had an expected life of 15–20 years. An inspection in 1997 showed some bubbles and delamination in the coating material at a flange. A 2002 inspection found some locations that had lack of adhesion to the base metal. In 2011, diminished flow was observed downstream of this line. Inspections revealed that a majority of the lining in one spool piece was loose or missing. The missing material had clogged a downstream orifice. A sample of the lining was sent to a testing lab where it was determined that cracking was evident on both the base metal and water side of the lining and there was a noticeable increase in the hardness of the in service sample as compared to an unused sample. (Reference ML12041A054).

- A licensee had experienced multiple instances of coating degradation resulting in coating debris found downstream in heat exchanger end bells. None of the debris had been large enough to result in reduced heat exchanger performance. (Reference ML12097A064).

- A licensee experienced continuing flow reduction over a 14 day period, resulting in a service water room cooler being declared inoperable. The flow reduction occurred due to the rubber coating on a butterfly valve becoming detached. (Reference ML073200779).

- At an international plant, cavitation in the piping system damaged the coating which subsequently resulted in unanticipated corrosion through the pipe wall. (Reference ML13063A135).

- A licensee experienced degradation of the protective concrete lining which allowed brackish water to contact the unprotected carbon steel piping resulting in localized corrosion. The degradation of the concrete lining was likely caused by the high flow velocities and turbulence from the valve located just upstream of the degraded area. (Reference ML072890132).

- A licensee experienced through-wall corrosion when a localized area of coating degradation resulted in base metal corrosion. The cause of the coating degradation was thought to have been nonage related mechanical damage. (Reference ML14087A210).

- A licensee experienced through-wall corrosion when a localized polymeric repair of a rubber lined spool failed. (Reference ML14073A059).

- A licensee experienced accelerated galvanic corrosion when loss of coating integrity occurred in the vicinity of carbon steel components attached to AL6XN components. (Reference ML12297A333).

These industry findings have been evaluated for applicability at MNGP and incorporated into this new AMP.

Plant-Specific Operating Experience

The following summary of plant-specific OE (which includes review of corrective actions and NRC inspections) provides examples of how MNGP is managing aging effects associated with the coatings on components managed by the MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP.

- An inspection in April 2013 identified degradation of the epoxy coating on a support plate for a RHRSW basket strainer. The epoxy coating protects the basket strainer base metal from corrosion. An ultrasonic inspection was performed and determined there was adequate wall thickness. A periodic inspection was performed every four years. The coatings were being adequately managed via inspection to identify degradation prior to significant loss of base metal. The basket strainer was downstream of the biocide and dispersant injection point, therefore that metal component was protected from MIC. An engineering evaluation of the degraded area where the epoxy was missing had only minor pitting and corrosion. The epoxy coating in all other areas was in good condition. Past inspection data was reviewed and based on a comparison of the current condition to the condition during the previous inspection, the minor pitting and corrosion were determined to not challenge the function of the basket strainer or the system. The engineering evaluation recommended periodic inspections done during on-line conditions as opposed to during outages. Subsequent UT inspections determined that no repairs were needed.

- In August 2017, MNGP personnel identified the need to update the requirements for the application of Service Level III coatings if deemed necessary during the inspection activity. Application requirements were deemed inadequate since the time of the previous performance of this PM. Action was taken to update the requirements. Updating of the inspection requirements reduces or eliminates the potential to miss opportunities to properly manage the aging effects of internal coatings.

- In October 2017, an inspection found that the 12-inch condensate makeup and reject pipe that protrudes into one of the CST tanks had a flaking coating. The coating was scraped to remove any lose material. The coating engineer reviewed a sample of the coatings and photographs and discussed the condition of the coating with the divers. The coating engineer determined that the remaining coating was tightly adhered to the pipe with no visible indications noted. No additional remediation of the coating was required. The coating condition did not affect the ability of the CST tanks to perform their design function and was evaluated to not have an impact on the function of downstream components.

- During an inspection of the CST tanks during a refueling outage in October 2017, the inspection identified minor pin-point rusting, broken and unbroken blisters, minor weld rusting, and an area of cracked coating. Indications similar to the ones listed above were found throughout the bottom plates of the tank. The coatings engineer stated that with intact blisters, oxygen permeability is negligible, and corrosion may be delayed indefinitely. Intact blisters have been documented as remaining unchanged in the CST tanks and other similar immersion areas. Pinpoint rusting is a type of corrosion that results in the formation of tiny, dispersed spots of rust across a metal surface. A preliminary engineering evaluation was performed to evaluate the acceptability of continued operation. Some indications were repaired during diving operations performed for the tank inspection and prior to demobilizing the diving operations and closing the tanks. An AR was initiated to address the aggregate of coating indications identified for the CST. An engineering evaluation provided guidance for management of unremedied coating indications in the other CST, provided justification for not repairing the indications, and guidelines for future monitoring of the indications. The remaining coating flaws were evaluated as acceptable through 2030 provided there is an intermediate inspection. This degradation does not affect the ability for the CSTs to perform their function.

- In November 2017, a preliminary evaluation of the findings from a refueling outage CST tank inspection determined that the indications would not affect the CST function (i.e., will not result in leakage from the CST nor result in coating detachment). Repairs were made to some indications and an engineering evaluation provided guidance for management of un-remediated coating indications in the CST, provided justification for not repairing the indications, and guidelines for future monitoring of the indications. The remaining coating flaws were evaluated as acceptable through 2030 provided there is an intermediate inspection. Actions for follow-up inspections were created as part of the resolution of this inspection.

AMP effectiveness will be assessed at least every five years per NEI 14-12.

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.29 ASME Section XI, Subsection IWE

The MNGP ASME Section XI, Subsection IWE AMP is an existing AMP that was formerly known as the MNGP Primary Containment In-Service Inspection Program. This AMP requires visual examinations of the accessible surfaces (base metal and welds) of the drywell, torus, vent lines, internal vent system, penetration assemblies and associated integral attachments. The program also requires examination of pressure retaining bolting and the drywell interior slab moisture barrier.

This AMP is performed in accordance with ASME Code Section XI, Subsection IWE, and consistent with 10 CFR 50.55a, *Codes and Standards*, with supplemental recommendations. This AMP will use the edition and addenda of ASME Section XI required by 10 CFR 50.55a, as reviewed and approved by the NRC staff for aging management under 10 CFR 54. Alternatives to these requirements that are aging management related will be submitted to the NRC, if required, in accordance with 10 CFR 50.55a prior to implementation.

This AMP includes periodic visual, surface, and volumetric examinations, where applicable, for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. Acceptability of inaccessible areas of steel containment vessel is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas. To provide reasonable assurance that moisture levels associated with an accelerated corrosion rate do not exist in the exterior portion of the MNGP steel containment drywell shell, the drywell air gap and sand pocket drain line outlets are monitored for blockage and leakage during each outage when the refueling cavity is flooded.

If plant-specific OE identified after the date of issuance of the initial renewed license triggers the requirement to implement a one-time supplemental volumetric examination, then this inspection is performed by sampling randomly selected, as well as focused, metal shell locations susceptible to corrosion that are inaccessible from one side. Guidance provided in EPRI TR-107514 (Reference 1.6.51) will be considered for sampling determinations. The trigger for this one-time examination is plant-specific occurrence or recurrence of metal shell corrosion (base metal material loss exceeding 10 percent of nominal plate thickness) that is determined to originate from the inaccessible side. Any such instance would be identified through code inspections performed since November 8, 2006. Based on a review of current MNGP OE, no such triggers have occurred.

Coated surfaces are visually inspected for evidence of conditions that indicate degradation of the underlying base metal. Coatings are a design feature of the base material and are not credited with managing loss of material. The MNGP Protective Coating Monitoring and Maintenance AMP (B.2.3.35) is used for the monitoring and maintenance of protective containment coatings in relation to reasonable assurance of Emergency Core Cooling System operability.

Surface conditions are monitored through visual examinations to determine the existence of corrosion. Surfaces are examined for evidence of flaking, blistering, peeling, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, or other signs of surface irregularities. Pressure-retaining bolting is examined for loosening and material conditions that cause the bolted connection to affect either containment leak-tightness or structural integrity. Internal and external moisture barriers are examined for wear, damage, erosion, tear, surface cracks, and other defects, which may violate their leak tight integrity.

Cumulative fatigue damage for the MNGP drywell penetration bellows is addressed in the Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis TLAA for SLR (Section 4.5). Cracking due to cyclic loading for portions of high-temperature drywell piping penetrations that are not pressurized during local leak rate testing and have no current licensing bases fatigue analysis will be managed by periodic supplemental surface or enhanced visual examinations incorporated into and consistent with the frequency of this AMP. This AMP will also include supplemental one-time inspections within 5 years prior to the SPEO for a representative sample of stainless steel penetrations and dissimilar metal welds that may be susceptible to SCC.

Examinations and evaluations are performed in accordance with the requirements of ASME Section XI, Subsection IWE, which provides acceptance standards for the containment pressure boundary components. Areas identified with damage or degradation that exceed acceptance standards require an engineering evaluation or require correction by repair or replacement. Such areas are corrected by repair or replacement in accordance with IWE-3000 or accepted by engineering evaluation.

NUREG-2191 Consistency

The MNGP ASME Section XI, Subsection IWE AMP, with enhancements, will be consistent with two exceptions to the 10 elements of NUREG-2191, Section XI.S1, *ASME Section XI, Subsection IWE*.

Exceptions to NUREG-2191

The Evaluation and Technical Basis discussions for the XI.S1 AMP in NUREG-2191 state that steel, stainless steel, and DMW pressure-retaining components that are subject to cyclic loading but have no CLB fatigue analysis are monitored for cracking (Element 3) and are supplemented with surface examination (or other applicable technique) in addition to visual examination to detect cracking (Element 4). The MNGP ASME Section XI, Subsection IWE AMP will take exception to this NUREG-2191 guidance as summarized below:

- The MNGP primary containment was designed to the requirements of ASME Code Section III, Subsection B, 1965 Edition with 1965 Winter Addenda. A fatigue evaluation was not required by the 1965 Edition or by original MNGP construction specifications. An assessment was performed to address the following design inputs for component materials comprising the MNGP primary containment that could be subject to cyclic loading but have no CLB fatigue analysis:

    (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 assessment concluded that the drywell shell, non-high temperature drywell penetrations, and penetration sleeves are subjected to a small and acceptable amount of fatigue such that neither fatigue analysis nor a fatigue waiver is required. As such, cracking due to cyclic loading does not require aging management for the drywell shell, non-high temperature drywell penetrations, and penetration sleeves.

- MNGP does not monitor for cracking utilizing supplemental surface examinations except at accessible portions of certain steel and stainless steel penetrations associated with high temperature systems. Original design and installation specifications for containment penetration components such as bellows, welds, and penetration adapters required surface examinations to ensure no flaws existed as part of initial installation. Appropriate testing is conducted for pressure boundary components per the 10 CFR Part 50, Appendix J AMP (B.2.3.31). Through-wall cracking would be detected by the Type A integrated leak rate test. Additionally, visual examinations are performed on accessible portions of the containment penetrations in accordance with the MNGP IWE Plan. Since issuance of the initial renewed license, MNGP has not experienced a failure of the subject containment components and integrated leak rate test results have been within the overall limits. Industry OE has also shown strong performance of the subject primary containment components. Thus, existing 10 CFR Part 50, Appendix J leak testing and ASME Section XI, Subsection IWE examinations at MNGP remain adequate for the drywell shell, non-high temperature drywell penetrations, and penetration sleeves without supplemental surface examination to detect cracking.

Enhancements

The MNGP ASME Section XI, Subsection IWE AMP will be enhanced as follows, for alignment with NUREG-2191. The one-time inspection will be started no earlier than five years prior to the SPEO. The enhancements will be implemented, and one-time inspection completed no later than six months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Revise procedures to specify the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of Research Council for Structural Connections publication *Specification for Structural Joints Using High-Strength Bolts*, for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts.
3. Parameters Monitored or Inspected	Revise procedures to specify that accessible noncoated surfaces (including those comprising the torus vent system) are monitored for arc strikes.
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Implement periodic supplemental surface or enhanced visual examinations, in addition to visual examinations, at intervals no greater than 10 years to detect cracking on accessible portions of high-temperature drywell piping penetrations that are not pressurized during local leak rate testing and have no CLB fatigue analysis. Cracking is corrected by repair or replacement or accepted by engineering evaluation.
4. Detection of Aging Effects	Conduct supplemental one-time surface or enhanced visual examinations, performed by qualified personnel using methods capable of detecting cracking, comprising a representative sample (five) of the stainless steel penetrations or DMWs associated with high-temperature (temperatures above 140°F) stainless steel piping systems in frequent use. These inspections are intended to confirm the absence of SCC aging effects. The one-time inspections will occur within five years prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise procedures to specify a one-time volumetric examination of metal shell surfaces that are inaccessible from one side if triggered by plant-specific OE identified after the date of issuance of the initial renewed license. If triggered, this inspection will be performed by sampling randomly selected, as well as focused, metal shell locations susceptible to corrosion that are inaccessible from one side. The trigger for this one-time examination is plant-specific occurrence or recurrence of metal shell corrosion (base metal material loss exceeding 10% of nominal plate thickness) that is determined to originate from the inaccessible side. Any such instance would be identified through code inspections performed since November 8, 2006. Guidance provided in EPRI TR–107514 will be considered when establishing a sampling plan. This sampling is conducted to demonstrate, with 95% confidence, that 95% of the accessible portion of the metal shell is not experiencing greater than 10% wall loss.
7. Corrective Actions	If SCC is identified as a result of the supplemental one-time inspections, additional inspections will be conducted in accordance with the site's corrective action process. This will include one additional penetration with DMWs associated with greater than 140°F stainless steel piping systems until cracking is no longer detected. Periodic inspection of subject penetrations with DMWs for cracking will be added to the MNGP ASME Section XI, Subsection IWE AMP if necessary, depending on the inspection results.

Operating Experience

Industry Operating Experience

Industry OE and NRC INs have documented occurrences of corrosion in steel containment shells, containment liners, and tori. MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. For example:

- NRC GL 87-05, *Request for Additional Information—Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells*, described drywell shell degradation that occurred in a Mark I containment as a result of water intrusion into the air gap between the outer drywell surface and the surrounding concrete. Subsequent wetting of the drywell shell occurred when the water flowed into the open sand pocket area at the bottom of the air gap. MNGP responded to the NRC regarding this industry OE in May 1987. As summarized in the OE discussion presented in ML16047A272, the sealing material between the refueling cavity and drywell air gap at MNGP was steel joined by watertight welds. An inspection for leakage from the refueling bellows was performed each refueling outage. Also, a flow switch was provided on the drywell refueling bellows leakage drain line to detect leakage from the seal area.

There are several paths to remove leakage from refueling or spillage of water into the drywell air gap. A channel with a four-inch drain line beneath the refueling bellows prevents leakage from entering the air gap. At the air gap-to-sand pocket interface, there is a galvanized steel plate sealed to the drywell shell and surrounding concrete. Four four-inch drain lines remove water that might collect on the plate from above. The sand pocket is provided with four two-inch drain lines (that are filled with sand to prevent loss of sand from the sand pocket while providing drainage).

Following the event described in this industry OE, the outlets for the sand pocket drains and the air gap drains were inspected at MNGP. Using compressed air to establish flow through each line, the drywell air gap lines were determined to be unobstructed from inlet to outlet. To ensure the drain lines remain unobstructed, the plant procedure for filling the reactor well includes a prerequisite to inspect the sand pocket and the air gap drain outlets prior to flooding the refueling area. MNGP operating history has shown no evidence of refueling seal leakage and no water was observed in the air gap during construction. Ongoing inspection and monitoring activities, as well as plant features that monitor for leaks past the bellows during refueling (i.e., local light indicator and Control Room panel alarm), adequately manage aging effects to ensure no loss of intended function.

- NRC IN 2006-01, *Torus Cracking in a BWR Mark I Containment*, described through-wall cracking and its probable cause in the torus of a Mark I containment. The cracking was identified by the licensee in the heat-affected zone at the high-pressure coolant injection (HPCI) turbine exhaust pipe torus penetration. The licensee concluded that the cracking was most likely initiated by cyclic loading due to condensation oscillation during HPCI operation. These condensation oscillations induced on the torus shell may have been excessive due to a lack of an HPCI turbine exhaust pipe sparger that many licensees have installed. MNGP has spargers installed for the exhaust pipes from the HPCI and RCIC System turbines. These devices will disperse the turbine exhaust steam limiting condensation oscillations and impingement loads imparted to the torus shell. The associated torus penetrations have large support structures installed both internally and externally to the penetration. These supports restrict exhaust line movement and distribute the penetration loads. Neither penetration is adjacent to a ring support or associated gusset plates. When the above event was reported in 2006, a walkdown of the two penetrations was completed by the PCT System engineer. No signs of any abnormalities were noted. To promote heightened awareness of potential failure mechanisms during inspections of the involved structures at MNGP, the subject OE was distributed and discussed during pre-job briefings with examiners assigned to perform torus inspections and integrated leak rate testing during the 2007 refueling outage.

- NRC IN 2011-15, *Steel Containment Degradation and Associated License Renewal Aging Management Issues*, described occurrences of corrosion in Mark I steel containments, both inside the suppression chamber (torus) and outside the drywell. As summarized in the OE discussion presented in ML16047A272, applicability to MNGP related to the potential for corrosion due to the presence of water in inaccessible areas and degradation of coatings and pitting corrosion of the torus steel shell or drywell. At MNGP, the primary potential water source is drywell refueling bellows leakage. As noted in discussion of GL 87-05 above, there are three drain paths for removing this leakage. When inspected in 1987, there was no indication of the presence of water. During flood up for refueling, there have been no indications of water leakage and no water has been observed at the drain lines. The refueling bellows were inspected prior to entering the PEO with no indication of bellows degradation due to cracking or loss of material. The presence of water beneath the refueling bellows, resulting in water entering the drywell air gap, would be indicated by an increase in water to the Radioactive Waste System. The presence of water at the air gap-to-sand pocket interface would be detected since the drain lines below the torus are monitored during refueling activities by procedure. Flooding in the sand pocket region would be indicated by water draining from the sand pocket drain lines. The evaluation included interviews with the primary containment ISI and protective coating and monitoring program owners and a review of AMP implementing documentation. The review confirmed that aging management activities were performed in accordance with established AMPs on a regular periodicity in accordance with detailed implementing procedures. The evaluation concluded that no additional actions were needed to address the issues identified in this industry OE.

- NRC IN 2014-07, *Degradation of Leak Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner*, described OE concerning degradation of floor weld leak-chase channel systems in three PWR containment designs that could affect leak tightness and aging management of containment structures. As summarized in the OE discussion presented in ML16047A272, construction of the MNGP metal containment is substantially different from a PWR metal containment. The MNGP Mark I containment does not have the leak-chase channel design that is reflected in the referenced PWR events. The review concluded that the existing inspection activities for other susceptible areas at MNGP were sufficient to guard against the problems of undetected corrosion on the containment noted in this industry OE.

- NRC Regulatory Issue Summary 2016-07, *Containment Shell or Liner Moisture Barrier Inspection*, described OE where moisture barriers were not correctly identified or were not properly inspected. As summarized in the OE discussion presented in ML16047A272, the moisture barrier (caulking) is located on the MNGP drywell interior (at the drywell shell-to-basemat interface) in a configuration that is essentially the same as the example used in ASME Section XI, Subsection IWE, Figure IWE-2500-1. As such, the accessible moisture barrier was examined with the method and frequency specified by the Code (i.e., in accordance with the requirements of ASME Section XI, Table IWE-2500-1, Item E1.30). Thus, the review concluded that the existing Code examinations and other activities at MNGP are sufficient to guard against undetected corrosion noted in this industry OE.

- Industry OE described an event at another BWR in March 2019 where insulation had not been removed prior to general visual examinations of containment boundary flued head components for certain piping penetrations. Evaluation of this OE determined that general visual examinations had not been performed for all accessible surface areas on the exterior of the drywell portion of containment (namely, flued head and other piping penetrations) during the second 10-year IWE interval at MNGP. Inspection of the subject surfaces was completed during the 2021 refueling outage. The applicable plant procedure was updated in May 2021 to add inspection requirements for external surfaces of the drywell at penetrations and to provide guidance for visual examination of insulated components.

These examples provide objective evidence that industry OE is being reviewed and evaluated to confirm that station testing procedures are effective to manage aging effects for ASME component supports.

<u>Plant-Specific Operating Experience</u>

Per the requirements of ASME Code Section XI, IWA-6230 and ASME Code Case N-532-5, MNGP submits an Owner’s Activity Report (OAR) summarizing inservice examination results and repair/replacement activities performed during a refueling cycle. OARs issued over the past ten years were reviewed for results applicable to IWE and no items were found pertinent to IWE.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program health report (July 2020) was reviewed. The overall program performance was exceptional (GREEN).

<u>Action Request Examples</u>

- During base metal examinations associated with the torus coating project in March 2007, arc strikes were noted on the interior of the torus shell. These arc strikes occurred during construction and only became visible after all coating was removed. The scheduled IWE examinations confirmed the superficial nature of these arc strikes (i.e., the thickness of the torus shell is acceptable; the base metal profile for coating was acceptable). Magnetic particle examinations confirmed that there were no linear indications (i.e., cracks) in the area of the arc strikes. No corrective actions were required.

- During scheduled IWE examinations in April 2011, a general visual examination identified minor thread damage on one of the northeast torus hatch studs. Detailed visual examination of the remaining fasteners for the hatch revealed no other damage. Examination results were reviewed against procedural and Code acceptance criteria by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program owner.

Although seven threads in the center region of the stud had minor deformation, there was no evidence of stud bending, twisting, or deformation. When assembled, the damaged area was within the unthreaded flange holes and not considered to be in the zone of thread engagement. Damage was attributed to worker practices, most likely from disassembly / reassembly or equipment ingress/egress from the torus. The minor thread damage did not affect the ability of the stud to maintain containment leak-tight or structural integrity. The torus hatch connection also received as-left pressure testing per the 10 CFR 50 Appendix J program following reassembly to verify its leak-tightness. The reported condition was determined to be acceptable for continued service per IWE-3122.1. No corrective actions were required.

- In March/April 2013, periodic ASME Section XI IWE examinations were performed as required by the IWE plan. Re-examinations of indications accepted by engineering evaluation during the previous refueling outage (i.e., in 2011) were also performed. Examination results for the underwater portion of the torus included new or changed areas of bare metal, some with magnetite or light surface rust, and also new or changed amounts of degraded coatings with pinpoint rust. An engineering evaluation concluded that the shallow depth of pits and the presence of thin oxide films indicates that pitting and general corrosion in the low oxygen, pure water environment of the MNGP torus was proceeding at a very slow rate. Given the low general and pitting corrosion rate, the torus shell was found acceptable for continued service in accordance with IWE-3122. No new indications were noted as a result of the concurrent coating inspections in the drywell, vent system, and torus vapor phase.

- The scheduled ASME Section XI IWE examinations of internal surfaces for the PCM (above and below the waterline) were performed concurrently with nuclear coatings inspections in April 2019. Underwater diving inspections near one of the ring girders identified three arc strikes in one bay and one pit in another bay. Base metal coating preparation performed on the arc strikes resulted in no noticeable metal loss. After surface preparation to support coating repair, pit depth was re-measured and confirmed to satisfy approved acceptance criteria for thinning near discontinuities. Coatings in these locations were repaired to preclude future pit growth and base metal degradation.

The above examples demonstrate that the examinations executed under the MNGP ASME Section XI, Subsection IWE AMP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

<u>Program Assessments and Evaluations</u>

Integrated Inspection reports issued over the last six years (2015 to 2021) were reviewed for NRC findings applicable to Containment ISI activities at MNGP. Aside from the concern regarding insulation removal discussed as Industry OE above (which was entered into the CAP in April 2021), no other findings considered NCVs related to the MNGP ASME Section XI, Subsection IWE AMP were identified by the NRC or self-identified by MNGP during this period.

A focused self-assessment was conducted in February 2010 to evaluate the readiness of the MNGP license renewal implementation project for an impending NRC post-approval inspection. The focused self-assessment included reviews of AMP basis documents, testing and inspections, and implementing procedures. The controlled version of the IWE inspection plan was reported to be several years out of date. Corrective actions to resolve all reported items were completed as part of license renewal implementation.

The NRC Post-Approval site inspection described in License Renewal Phase II Inspection Report for MNGP was reviewed regarding the MNGP ASME Section XI, Subsection IWE AMP. The inspectors reviewed the licensing basis, program basis document, examination records, and related ARs. The inspectors also interviewed plant personnel responsible for the program. The inspectors concluded that the applicable commitment (to include inspection of all accessible painted surfaces inside containment in applicable procedures), license conditions, and regulatory requirements were being met by the ASME Section XI, Subsection IWE AMP.

A snapshot self-assessment of the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program was conducted in January-February 2019 in advance of an NRC refueling outage inspection. The scope of the review included a sampling of ISI activities spanning the prior two years for procedural and code compliance. Industry OE and records of NRC violations during the same time period were reviewed for applicability. Conclusions stated that MNGP has three qualified ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP owners/backups on site, each with many years of experience in the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program and in related NDE and welding programs. No areas for improvement were noted; however, a recommended enhancement to clarify reporting and acceptance criteria for rust was incorporated into the IWE Plan for the third 10-year inspection interval.

A focused self-assessment was conducted in September 2019 in preparation for the License Renewal Phase IV NRC inspection. The focused self-assessment included review of AMP basis documents, an evaluation of changes against the requirements of 10 CFR 54.37(b), and documentation of training for AMP owners. Along with the need to assign program owners and schedule periodic self-assessments for AMPs, the report identified various additional areas for improvement. Corrective actions to resolve all reported items were completed as part of license renewal implementation. None had an impact to the ASME Section XI, Subsection IWE AMP.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and some findings were identified related to the MNGP ASME Section XI, Subsection IWE AMP. Findings were administrative in nature and as a result general updates due to organizational and process changes were made in the AMP basis document.

The MNGP ASME Section XI, Subsection IWE AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP ASME Section XI, Subsection IWE AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.30 ASME Section XI, Subsection IWF

The ASME Section XI, Subsection IWF AMP is an existing AMP that consists of periodic visual examination of supports for ASME Class 1, 2, 3, and MC piping and components for signs of degradation such as corrosion; cracking; deformation; misalignment of supports; missing, detached, or loosened support items; loss of integrity of welds; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Bolting for Class 1, 2, and 3 piping and component supports is also included and inspected for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity.

The ASME Section XI, Subsection IWF AMP provides inspection and acceptance criteria and meets the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, 2007 edition with addenda through 2008, and 10 CFR 50.55a(b)(2) for Class 1, 2, 3, and MC piping and components and their associated supports. The primary inspection method employed is visual examination. NDE indications are evaluated against the acceptance standards of ASME Code Section XI. Examinations that reveal indications are evaluated. Examinations that reveal flaws or relevant conditions that exceed the referenced acceptance standard are expanded to include additional examinations during the current outage. The scope of inspection for supports is based on sampling of the total support population. The sample size varies depending on the ASME Code classification.

This AMP emphasizes proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload for structural bolting. As noted below in the enhancement discussion, the AMP also includes preventive actions for storage requirements of high-strength bolts and ensuring that molybdenum disulfide (MoS_2) and other lubricants containing sulfur are not used for structural bolting. The requirements of ASME Code Section XI, Subsection IWF are supplemented to include volumetric examination of high-strength bolting for cracking. This AMP will also include a one-time inspection within 5 years prior to the SPEO of an additional 5 percent of piping supports from the remaining IWF population that are considered most susceptible to age-related degradation. Inspections of elastomeric vibration isolation elements to detect hardening are also included if the vibration isolation function is suspect.

NUREG-2191 Consistency

The MNGP ASME Section XI, Subsection IWF AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S3, *ASME Section XI, Subsection IWF*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP ASME Section XI, Subsection IWF AMP will be enhanced as follows, for alignment with NUREG-2191. The one-time inspection will be started no earlier than five years prior to the SPEO. The enhancements will be implemented, and one-time inspection completed no later than six months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Revise procedures to evaluate the acceptability of inaccessible areas (e.g., portions of ASME Class 1, 2, and 3 supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions are identified in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
2. Preventive Actions	Revise procedures to clarify that in addition to molybdenum disulfide (MoS_2), other lubricants containing sulfur will be prohibited from use on structural bolting.
2. Preventive Actions	Revise procedures to specify the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of Research Council for Structural Connections publication *Specification for Structural Joints Using High-Strength Bolts* for structural bolting consisting of ASTM A325, ASTM A490, and equivalent bolts.
3. Parameters Monitored or Inspected	Revise procedures to specify that elastomeric or polymeric vibration isolation elements are monitored for cracking, loss of material, and hardening.
3. Parameters Monitored or Inspected	Revise procedures to specify that accessible sliding surfaces are monitored for significant loss of material due to wear and accumulation of debris or dirt.
4. Detection of Aging Effects	Perform and document a one-time inspection of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. The one-time inspection will occur within five years prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise procedures to include tactile inspection (feeling, prodding) of elastomeric vibration isolation elements to detect hardening if the vibration isolation function is suspect.
4. Detection of Aging Effects	Revise procedures to specify that, for component supports with high-strength bolting greater than one-in. nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. A representative sample of bolts will be inspected during the inspection interval prior to the start of the SPEO and in each 10-year period during the SPEO. Identify the population of ASME Class 1, 2, 3, and MC high-strength structural bolting greater than one-in. nominal diameter within the boundaries of IWF-1300 and establish a sample to be 20% of the population (for a material/environment combination) up to a maximum of 25 bolts.
5. Monitoring and Trending	Revise procedures to increase or modify the component support inspection population when a component support is repaired to as-new condition by including another support that is representative of the remaining population of supports that were not repaired.
6. Acceptance Criteria	Revise procedures to specify that the following conditions are also unacceptable: • Loss of material due to corrosion or wear; • Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support; • Cracked or sheared bolts, including high-strength bolts, and anchors; • Loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function; and • Cracks.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. For example:

- Degradation of threaded bolting and fasteners has occurred from boric acid corrosion, SCC, and fatigue loading (U.S. NRC Inspection and Enforcement Bulletin (IEB) 82-02, *Degradation of Threaded Fasteners In the RCPB of PWR Plants*, NRC GL 91-17, *Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants*). SCC has occurred in high-strength bolts used for NSSS component supports (EPRI NP-5769).

- NRC IN 2009-04 describes deviations in the supporting forces of mechanical constant supports, from code allowable load deviation, due to age-related wear on the linkages and increased friction between the various moving parts and joints within the constant support, which can adversely affect the analyzed stresses of connected piping systems. This OE was evaluated for MNGP. Based on vendor evaluation of the subject support units, the findings reported in this OE were determined to result from unforeseen system vibration and not age-related degradation. The only comparable supports within the scope of the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program are on the recirculation pumps inside the drywell, which undergo periodic visual examinations. These supports are not located in areas with high vibration and will not be subjected to the conditions described in this OE. Thus, the review concluded that no additional actions were required.

- Industry OE described an event where RV supports were not included in the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and IWF exams were not being performed. This OE was evaluated for MNGP and distributed (for information only) to the engineering department for further review. Examples of the same issue were identified in a proactive search using OE obtained from other stations, NRC, INPO, and other industry sources spanning a period from 2008 through 2016. The MNGP reactor vessel supports are included in the fifth Interval Plan and have been inspected as scheduled during refueling outages subsequent to plan implementation in September 2012.

- Industry OE described an event at Sequoyah Nuclear Plant Unit 2 (a PWR) where CRDM Supports were not added to the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program, and IWF exams were not being performed. This OE was evaluated for MNGP. A subject matter expert noted that the CRDM seismic support assembly as described in the OE report is not a component associated with BWRs; the item was already known by the MNGP ISI engineer. Thus, the review concluded that this OE does not have applicability to the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program.

These examples provide objective evidence that industry OE is being reviewed and evaluated to confirm that station testing procedures are effective to manage aging effects for ASME component supports.

Plant-Specific Operating Experience

Per the requirements of ASME Code Section XI, IWA-6230 and ASME Code Case N-532-5, MNGP submits an Owner's Activity Report (OAR) summarizing inservice examination results and repair/replacement activities performed during a refueling cycle. OARs issued in the last six years (2015 to 2021) were reviewed for results applicable to IWF and the following instances were noted:

- A slightly bent rod was evaluated as acceptable for continued service on Class 2 piping support during the 2017 Refueling Outage.
- Missing locking nuts were installed on a U-bolt for a Class 1 piping support; the locking nuts were tightened and installation corrected on eye rods for a Class 2 piping support during the 2019 Refueling Outage.

No other OAR items pertinent to IWF were found.

The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program health report (July 2020) was reviewed. The overall program performance was exceptional (GREEN).

Action Request Examples

- During a scheduled VT-3 examination in April 2015, a difference was identified between the as-built orientation for a MST System snubber and the associated design drawings. A piping analysis was performed, new cold setting values for impacted hangers were established, and affected documents updated. The evaluation concluded that the as-found snubber configuration was acceptable.
- During a scheduled VT-3 examination in April 2017, a center punch was observed in the gap between a paddle and clamp on a seismic restraint for the Emergency Core Cooling System ring header. As the strut was free to rotate around the attachment pin, the restraint was still capable of performing its intended function. The debris was removed from the restraint.
- During a scheduled VT-3 examination in April 2019, a loose nut was found on the eye rod at the top of a spring can support for the high pressure coolant injection turbine steam line. Based on its mounting configuration (threaded to the spring can and beam attachment above the support), the eye rod would not loosen or detach from the spring can if the nut in question were loose. Thus, the support was still capable of performing its intended function. The condition was corrected and a satisfactory pre-service VT-3 examination was completed.
- During a scheduled VT-3 examination in February 2021, a difference was identified between the as built orientation for a RCIC System snubber and the

associated support drawing. The ability to pivot the snubber by hand demonstrated that the snubber maintained freedom of movement at both ends; thus, the support was still capable of performing its intended function. The snubber was changed out during the 2021 refueling outage and a satisfactory pre-service VT-3 examination was performed following the snubber changeout activity in accordance with plant procedure.

The above examples demonstrate that the examinations executed under the MNGP ASME Section XI, Subsection IWF AMP are effective in evaluating degraded conditions and implementing activities to maintain component intended function.

Program Assessments and Evaluations

Integrated Inspection reports issued over the last six years (2015 to 2021) were reviewed for NRC findings applicable to ISI activities at MNGP. During this period, no findings considered NCVs related to the MNGP ASME Section XI, Subsection IWF AMP were identified by either the NRC or self-identified by MNGP.

A focused self-assessment was conducted in February 2010 to evaluate the readiness of the MNGP license renewal implementation project for an impending NRC post-approval inspection. The focused self-assessment included reviews of AMP basis documents, testing and inspections, and implementing procedures. The controlled version of the ISI inspection plan was reported to be several years out of date and additional implementing documents were identified for the ASME Section XI, Subsection IWF AMP. Corrective actions to resolve all reported items were completed as part of license renewal implementation.

The NRC post-approval site inspection described in License Renewal Phase II Inspection Report (Reference ML102450165) for MNGP was reviewed regarding the MNGP ASME Section XI, Subsection IWF AMP. The inspectors reviewed the licensing basis, program basis document, examination records, and related ARs. The inspectors also interviewed plant personnel responsible for the program. The inspectors concluded that the applicable commitment (to provide inspections of ASME Class MC component supports), license conditions, and regulatory requirements were being met by the ASME Section XI, Subsection IWF AMP.

A snapshot self-assessment of the MNGP ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program was conducted in January-February 2019 in advance of an NRC refueling outage inspection. The scope of the review included a sampling of ISI activities spanning the prior two years for procedural and code compliance. Industry OE and records of NRC violations during the same time period were reviewed for applicability. Conclusions stated that MNGP has three qualified ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection AMP owners/backups on site, each with many years of experience in the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program and in related NDE and welding programs. No areas for improvement were noted; however, several recommended enhancements or clarifications to refresh the ISI 5th Interval Plan and make requirements or descriptions clearer for the user were implemented.

A focused self-assessment was conducted in September 2019 in preparation for the License Renewal Phase IV NRC inspection. The focused self-assessment included review of AMP basis documents, an evaluation of changes against the requirements of 10 CFR 54.37(b), and documentation of training for AMP owners. Along with the need to assign program owners and schedule periodic self-assessments for AMPs, the report identified various additional areas for improvement. Corrective actions to resolve all reported items were completed as part of license renewal implementation. None had an impact to the ASME Section XI, Subsection IWF AMP.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and some findings were identified related to the MNGP ASME Section XI, Subsection IWF AMP. Findings were administrative in nature which included general updates due to organizational and process changes were made in the AMP basis document and text in the USAR was updated to reflect status for LR commitments.

The MNGP ASME Section XI, Subsection IWF AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP ASME Section XI, Subsection IWF AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

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B.2.3.31 10 CFR Part 50, Appendix J

The MNGP 10 CFR Part 50, Appendix J AMP is an existing AMP that is a performance monitoring program that monitors the leakage rates through the primary containment pressure-retaining boundary and individual penetration isolation barriers. Corrective actions are taken if leakage rates exceed the acceptance criteria dictated in the MNGP Technical Specifications and the associated administrative limits.

This AMP is implemented in accordance with 10 CFR Part 50, Appendix J, as modified by approved exemptions. The program is based on NEI 94-01 Revision 2-A (Reference ML100620847), *Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J*, with approve exceptions.

The MNGP containment system consists of the containment including electrical, mechanical, equipment hatch, and personnel airlock penetrations. As described in 10 CFR Part 50, Appendix J, periodic containment leak rate tests are required to ensure that (a) leakage through the containment pressure-retaining boundary and individual penetration isolation barriers does not exceed allowable leakage rates specified in the MNGP Technical Specifications and (b) integrity of the containment structure is maintained during its service life. Appendix J of 10 CFR Part 50 provides two options, Option A and Option B, to meet the requirements of a containment leak rate test (LRT) program. MNGP uses the performance-based approach, Option B.

The monitored parameters are leakage rates through the primary containment pressure-retaining boundary and individual penetration isolation barriers. Three types of tests (Type A, Type B, and Type C) are performed at MNGP as specified by 10 CFR Part 50, Appendix J, Option B. Type A integrated leak rate tests (ILRT) determine the overall containment integrated leakage rate at the calculated peak containment internal pressure related to the design basis loss of coolant accident. Type B (containment penetration leak rate) tests detect local leaks and measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Type C (containment isolation valve leak rate) tests detect local leaks and measure leakage across containment isolation valves installed in containment penetrations or lines penetrating the containment. Testing and leakage criteria for Main Steam Lines and the primary containment airlock are specified in accordance with the plant Technical Specifications.

For containment pressure boundary components that do not receive scheduled Type B or Type C tests, the following programs also manage applicable aging effects:

- ASME Section IX, Subsection IWE AMP (B.2.3.29) for the penetration assemblies
- External Surfaces Monitoring of Mechanical Components AMP (B.2.3.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.3.24)

- Water Chemistry AMP (B.2.3.2) for internal surface of pertinent components, as verified by the One-Time Inspection AMP (B.2.3.20) for internal surface of pertinent components

- Fatigue Monitoring (B.2.2.1)

Additionally, 10 CFR Part 50, Appendix J requires a general visual inspection of the accessible interior and exterior surfaces of the containment SCs to be performed prior to any Type A test and at periodic intervals between tests based on the performance of the containment system. The MNGP 10 CFR Part 50, Appendix J AMP meets this requirement with its visual inspection procedures. Additionally, the MNGP 10 CFR Part 50, Appendix J AMP visual inspections may be performed in conjunction with the MNGP ASME Section XI, Subsection IWE AMP to ensure that evidence of structural deterioration that may affect the containment structure leakage, integrity, or the performance of the Type A test is identified. Furthermore, for portions of high temperature piping penetrations that are not pressurized during local leak rate testing and do not have a CLB fatigue analysis, the Appendix J general visual examinations will be supplemented by surface or enhanced visual examinations under the ASME Section IX, Subsection IWE (Section B.2.3.29) AMP for applicable areas of penetrations subject to cyclic loading to detect potential cracking..

When leakage rates do not meet the acceptance criteria, an evaluation is performed to identify the cause of the unacceptable performance and appropriate corrective actions are taken.

NUREG-2191 Consistency

The MNGP 10 CFR Part 50, Appendix J AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.S4, *10 CFR Part 50, Appendix J*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE program and takes appropriate corrective actions.

NRC IN 92-20 was issued to alert licensees to problems with local leak rate testing of two-ply stainless-steel bellows used on piping penetrations at some plants. Specifically, local leak rate testing could not be relied upon to accurately measure the leakage rate that would occur under accident conditions since, during testing, the two plies in the bellows were in contact with each other, restricting the flow of the local leak rate test medium to potential crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. The MNGP containment design includes bellows on hot fluid piping penetrating the containment. The applicable test procedures for the bellows were informed by this industry OE to ensure the proper testing.

Plant-Specific Operating Experience

The MNGP 10 CFR Part 50, Appendix J program performs periodic testing of the primary containment to ensure any leakage remains well within the leakage assumed in the MNGP accident analysis. To ensure this, administrative limits are established for each tested penetration that is a fraction of the overall limit and an integrated limit for the as-found and as-left containment performance is maintained via the Master Local Leak Test procedure. Throughout the PEO, the monitoring, trending, and maintenance activities associated with the program have successfully maintained containment leakage within the overall limits. A review of condition reports associated with the program over the last 10 years indicates most conditions were exceedance of the administrative limits for individual penetrations that do not result in exceeding Technical Specification limits. For example, the following issues were identified and entered into the CAP:

- In April 2019, testing of the "C" outboard main steam isolation valve measured an as-found leakage rate exceeding the administrative limit set by the program but remained within the Technical Specification limit. Maintenance was initiated to restore the performance of the valve to within the administrative limit.
- In April 2019, testing of the "B" outboard main steam isolation valve measured an as-found leakage rate exceeding the administrative limit set by the program but remained within the Technical Specification limit. Maintenance was initiated to restore the performance of the valve to within the administrative limit.
- In April 2019, the Torus outboard Isolation valve to the containment oxygen analyzer exceeded its administrative leakage limit during Appendix J testing. Maintenance was performed on the valve actuator and as-left leakage was restored to within the administrative limit.
- In June 2017, the RCIC System inboard steam isolation valve exceeded its administrative leakage limit during Appendix J testing. The leakage was evaluated as acceptable to defer repairs to a later outage. A work order initiated to repair the valve in the following outage. The valve test frequency was removed from the extended test interval. During the following outage, the valve tested within the administrative limit.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and no findings were identified related to the MNGP 10 CFR Part 50, Appendix J AMP.

The MNGP 10 CFR Part 50, Appendix J AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP 10 CFR Part 50, Appendix J AMP provides reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.32 Masonry Walls

The MNGP Masonry Walls AMP is an existing AMP that is currently implemented as part of the MNGP Structures Monitoring Program. The MNGP Masonry Walls AMP was evaluated as a portion of the MNGP Systems and Structures Monitoring AMP in the initial LRA. The Masonry Walls AMP is evaluated separately in the SLRA and is compared to the NUREG-2191, Section XI.S5 program. This condition monitoring AMP is based on NRC IE Bulletin 80-11, *Masonry Wall Design*, and monitoring proposed by NRC IN 87-67, *Lessons Learned from Regional Inspections of Licensee Actions in Response to IE 80-11*, for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained.

The MNGP Masonry Walls AMP is a condition monitoring program that provides for inspection of masonry walls for loss of material and cracking through monitoring potential shrinkage and/or separation. The AMP will be enhanced to monitor and inspect for shrinkage and/or separation as well as loss of material at the mortar joints and gaps between supports and masonry walls, to include specific monitoring, measurement, and trending of widths and lengths of cracks and of gaps between supports and masonry walls, and to include specific assessment of the acceptability of crack widths and lengths and gaps between supports and masonry walls. The program relies on periodic visual inspections, conducted at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of license renewal so that the established design basis for each masonry wall remains valid during the SPEO. Qualifications of inspection and evaluation personnel are in accordance with ACI 349.3R. Unacceptable conditions, when found, are evaluated, or corrected in accordance with the CAP.

Masonry walls that are fire barriers are also managed by the MNGP Fire Protection AMP (B.2.3.15).

NUREG-2191 Consistency

The MNGP Masonry Walls AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.S5, *Masonry Walls*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Masonry Walls AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Enhance the implementing procedure to include the inspection of masonry walls in the EFB and Radwaste Building.
3. Parameters Monitored or Inspected	Enhance the implementing procedure to monitor and inspect for gaps between the supports and masonry walls that could potentially impact the intended function or potentially invalidate its evaluation basis.
4. Detection of Aging Effects	Enhance the implementing procedure to include provisions for more frequent inspections in areas where significant loss of material, cracking, or other signs of degradation are projected or observed to provide reasonable assurance than there is no loss of intended function between inspections.
5. Monitoring and Trending	Enhance the implementing procedure to include trending of widths and lengths of cracks and gaps between supports and masonry walls that approach or exceed acceptance criteria.
5. Monitoring and Trending	Enhance the implementing procedure to include projected degradation until the next scheduled inspection where it is practical.
6. Acceptance Criteria	Enhance the implementing procedure to include acceptance criteria for masonry wall inspections that will be used to ensure observed aging effects (cracking, loss of material, or gaps between the structural steel supports and masonry walls) do not invalidate the evaluation basis of the wall or impact its intended function.
7. Corrective Actions	Enhance the implementing procedure to ensure that if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the MNGP CAP.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

Plant-Specific Operating Experience

The following review of plant-specific OE demonstrates how MNGP is managing aging effects associated with the MNGP Masonry Walls AMP.

- A masonry wall was discovered to potentially not be within the allowable stresses as it was built. After analyzing the wall, the wall was determined to be operable but non-conforming because it may not be able to meet the allowable stresses during a HELB event. The wall was modified to meet the allowable stresses of a HELB event.
- During an inspection for aging management, a crack in a block wall was discovered. An evaluation determined the wall was acceptable and a work order for the repair of the wall was created.
- During structural surveillance, deterioration of the NW corner exterior masonry wall of the screenhouse was identified. The deterioration was determined to not affect the function of the building. The wall was repaired, and the work order was closed.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Masonry Walls AMP.

The MNGP Masonry Walls AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Masonry Walls AMP, with enhancements, provides reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.33 Structures Monitoring

The Structures Monitoring AMP is an existing AMP based on the requirements of 10 CFR 50.65 (the Maintenance Rule) and NRC RG 1.160 (Reference 1.6.52), and Nuclear Management and Resources Council 93-01 (Reference 1.6.53). These documents provide guidance for development of site/fleet-specific programs to monitor the condition of structures and structural components within the scope of the SLR rule, such that there is no loss of structure or structural component intended function.

The MNGP Structures Monitoring AMP consists primarily of periodic visual inspections of plant SCs for evidence of deterioration or degradation, such as described in the American Concrete Institute (ACI) Standards 349.3R (Reference 1.6.54), ACI 201.1R (Reference 1.6.55), and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11 (Reference 1.6.56). Quantitative acceptance criteria for concrete inspections are based on ACI 349.3R.

Inspections and evaluations are performed by personnel qualified in accordance with GALL-SLR requirements using criteria derived from industry codes and standards contained in the plant CLB including but not limited to ACI 349.3R, ACI 318, SEI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications, as applicable. The AMP includes preventive actions to ensure structural bolting integrity. The program also includes periodic sampling and testing of ground water and the need to assess the impact of any changes in its chemistry on below grade concrete structures.

Included in the program is: inspection of structures, including SR buildings and the internal structures within containment; inspection of NSR related structures; inspection of structural steel elements; inspection of elastomers, which includes nonmetallic polymer materials used in seals and gaskets and equipment vibration isolation mounts; and inspection of the component supports commodity group and architectural items.

Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of aging effects requiring management. Coatings are not credited for license renewal but are used to indicate aging effects of the base material.

Periodic ground water level measurements and chemical analysis of ground/lake water are performed to verify the associated chemistry remains non-aggressive. The frequency of monitoring ground water chemistry (pH, chlorides, and sulfates) is monthly.

NUREG-2191 Consistency

The MNGP Structures Monitoring AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S6, *Structures Monitoring*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Structures Monitoring AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Revise the implementing procedure to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the *Research Council for Structural Connections publication, Specification for Structural Joints Using High-Strength Bolts* will be used.
3. Parameters Monitored or Inspected	Revise the implementing procedure to include monitoring and trending of leakage volumes and chemistry for signs of concrete or steel reinforcement degradation if active through-wall leakage or groundwater infiltration is identified.
4. Detection of Aging Effects	Revise the implementing procedure to include provisions for more frequent inspections in areas where significant signs of degradation are projected or observed to provide reasonable assurance than there is no loss of intended function between inspections.
4. Detection of Aging Effects	Revise the implementing procedure to include evidence of water in-leakage as a finding requiring further evaluation. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessment may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise the implementing procedure to include tactile inspection in addition to visual inspection of elastomeric elements to detect hardening.
4. Detection of Aging Effects	Revise the implementing procedure to include qualification requirements for both inspection and evaluation personnel that are in accordance with ACI 349.3R.
4. Detection of Aging Effects	Revise the implementing procedure to explicitly include inspection of the following components and commodities: • Expansion plugs • Fuel Storage Racks (New Fuel) • Manhole covers, supports • Supports • Concrete Diesel Fuel Oil Storage Tank Deadmen • Vibration Isolation Elements • Electrical Enclosures • RPV to Drywell Refueling Seal • Exterior Surfaces of Roofing
6. Acceptance Criteria	Revise the implementing procedure to include acceptance criteria for concrete surfaces based on the “second-tier” evaluation criteria provided in ACI 349.3R.
7. Corrective Actions	Revise the implementing procedure to include that if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the MNGP CAP.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE program and takes appropriate corrective actions.

A five-year effectiveness review for MNGP AMPs was completed which included a proactive OE search. INPO Report 12-57 was identified which describes shield building cracking of concrete. This event did not result in any impacts to the program.

NUREG–1522 documents the results of a survey sponsored in 1992 by the Office of Nuclear Reactor Regulation to obtain information on the types of distress in the concrete and steel SCs, the type of repairs performed, and the durability of the repairs. IN 2011-20 "Concrete Degradation by Alkali-Silica Reaction" (November 18, 2011) discusses an instance of ground water infiltration leading to alkali-silica reaction degradation in below-grade concrete structures, while IN 2004-05 and IN 2006-13 discuss instances of through-wall water leakage from spent fuel pools. NUREG/CR–7111 provides a summary of aging effects of SR concrete structures. There is reasonable assurance that implementation of the structures monitoring program described above will be effective in managing the aging of the in-scope SC supports through the period of SLR.

Identified degradation mechanisms are included in the NUREG-2191 Structures Monitoring AMP.

Plant-Specific Operating Experience

- During a structures walkdown, blistering and peeling paint was found around a grouted pipe penetration. The paint was determined to not affect the grouted penetration or impact any SSCs. The peeling paint was removed, and the area was repainted and sealed.
- Corrosion was found on the off-gas stack supports and hangers. The vents on the lower part of the stack were sealed. The lack of air flow and presence of moisture could potentially be accelerating the corrosion. A condition evaluation was performed which determined there were no adverse conditions and no resulting actions were required.
- Leaking was identified in the Diesel Oil Pump House after a large concrete slab was placed on the roof as a missile shield. The water intrusion was determined to be from a pipe penetration. There was evidence that the flow of run-off water had changed and that recent rains around the building resulted in leakage into the pump house. Sampling was performed that confirmed no indications of oil leakage. Minor maintenance was performed to seal the penetration and apply fill material to grading near the pump to direct water away from the structure.
- Mineral deposits were found accumulating on the west wall of the HPCI room. The area was evaluated, and no signs of concrete degradation or lack of structural integrity were identified. The mineral accumulation was determined to have no effect to the operability or functionality of any equipment in the area. The condition evaluation performed stated that this condition had previously been captured in the surveillance program and was being monitored.
- During a periodic structural inspection, the support pedestals for the stairs leading to 2nd floor inside the off-gas stack were identified as being degraded and rusted. Immediate action was taken to have an engineer evaluate the usability of the stairway, and a previous AR was identified that had evaluated the condition and the acceptability for use. Temporary supports were placed under the stairs until a permanent fix could be completed. A WO was initiated, and the condition was repaired.

- During a periodic structural inspection, a door frame was found rusted through at the floor level. The frame was repaired and repainted.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Structures Monitoring AMP.

The MNGP Structures Monitoring AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Structures Monitoring AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is an existing AMP that is currently implemented as part of the MNGP Structures Monitoring Program. The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP was evaluated as a portion of the MNGP Systems and Structures Monitoring AMP in the initial LRA. The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is evaluated separately in the SLRA, and it is compared to the NUREG-2191, Section XI.S7 program.

This condition monitoring AMP addresses age-related deterioration, degradation due to environmental conditions, and the effects of natural phenomena that may affect water-control structures. The program consists of inspection and surveillance of water control structures. The only structure within the scope of the MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is the INS. Parameters monitored are in accordance with RG 1.127 and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Inspections occur at least once every five years. Evaluation of ground water chemistry is performed under the scope of the MNGP Structures Monitoring AMP periodically to assure the groundwater remains non-aggressive.

The U.S. NRC RG 1.127, *Inspection of Water-Control Structures Associated with Nuclear Power Plants*, provides detailed guidance for an inspection program for water-control structures, including guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports. NRC RG 1.127 delineates current NRC practice in evaluating ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program for water-control structures. Although MNGP is not committed to RG 1.127, this AMP addresses water-control structures, commensurate with the guidance of NRC RG 1.127.

NUREG-2191 Consistency

The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S7, *Inspection of Water-Control Structures Associated with Nuclear Power Plants*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
2. Preventive Actions	Revise the implementing procedure to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, *Specification for Structural Joints Using High-Strength Bolts*, will be used.
4. Detection of Aging Effects	Enhance the implementing procedure to state that further evaluation of evidence of groundwater infiltration or through-concrete leakage may also include destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels, and that assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the leakage water if leakage volumes allow.
4. Detection of Aging Effects	Enhance the implementing procedure to state that visual inspections of inaccessible concrete for evidence of leaching of calcium hydroxide and carbonation are performed, when exposed.
4. Detection of Aging Effects	Enhance the implementing procedure to include qualification requirements for both inspection and evaluation personnel that is in accordance with ACI 349.3R.
5. Monitoring and Trending	Enhance the implementing procedure to include trending of quantitative measurements and qualitative information for findings exceeding the acceptance criteria for all applicable parameters monitored or trended.

Operating Experience

<u>Industry Operating Experience</u>

MNGP evaluates industry OE items for applicability per the OE program and takes appropriate corrective actions. Degradation of water-control structures has been detected, through NRC RG 1.127 programs, at a number of nuclear power plants, and, in some cases, it has required remedial action. NRC NUREG-1522, *Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures* described instances and corrective actions of severely degraded steel and concrete components at the INS and pump house of coastal plants. Other degradation described in the NUREG includes appreciable leakage from the spillway gates, concrete cracking, corrosion of spillway bridge beam seats of a plant dam and cooling canal, and appreciable differential settlement of the outfall structure of another. No loss of intended functions has resulted from these occurrences. Therefore, the inspections implemented in accordance with the guidance in NRC RG 1.127 have been successful in detecting significant degradation before loss of intended function occurs.

<u>Plant-Specific Operating Experience</u>

- During a flood walkdown of the INS, a hole was found leading to the screen house approximately three feet east of a door that was due to an unsealed penetration. The penetration was sealed.

- During Fukushima flooding walkdowns of the INS, conduit penetrations were identified as potential leakage pathways. The penetrations were identified as potential leakage paths despite having no effect on the components intended function to reduce the actions required in an emergency situation. The penetrations were sealed.

- Degradation of the INS roof coating was identified. Water was also found leaching through the concrete due to leaks in the roof. Three leaking/leaching locations were found. An evaluation was performed based on a walkdown by engineering which confirmed no visible signs of rebar corrosion. The action was closed to recoat the roof. No further degradation was detected. The structural integrity of the INS was unaffected and no in-scope SSCs were impacted.

- What appeared to be corrosion products were observed on the south wall of the INS, adjacent to the circulating water discharge pipe. An evaluation was performed, and the walls were monitored per the structural alignment management surveillance. A comparison to pictures taken indicated no change. The brown color was likely leaching from the waterproofing material that was applied on the exterior of the buildings. The material could be viewed at some penetrations as well. The evaluation determined that the concrete did not show distress and did not appear to involve corrosion of concrete steel reinforcement. The circulating water pipe appears to have general surface corrosion and was unaffected by the water in-leakage. The evaluation concluded that no additional actions were required and to continue to monitor the area.

- A study was completed on the roof of the INS by American Engineering and Testing (AET). Repairs were recommended in order to maintain the roof. There were no immediate concerns that would affect the equipment within the INS. An evaluation discussed a number of actions including calculations that were performed to confirm the structural integrity of the intake building roof.

- A water leak was identified in the drop hatch above the EDG-ESW in the ceiling of the INS. Water was dripping into a cable tray and running off and collecting in a small pool in front of the door leading to the screen house. Although no in-scope SSCs were affected by this leak, the hatch was sealed to stop the leak.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP.

The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP, with enhancements, provides reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.35 Protective Coating Monitoring and Maintenance

The MNGP Protective Coating Monitoring and Maintenance AMP is an existing AMP. This AMP consists of guidance for selection, application, inspection, and maintenance of the Service Level I protective coatings inside the MNGP primary containment, on both steel and concrete substrates. Maintenance of Service Level I coatings applied to steel surfaces inside containment can reduce loss of material due to corrosion of steel components and aid in decontamination but is not credited for these functions. Degraded or unqualified coatings can affect post-accident operability of ECCS and therefore, a program to manage aging effects on Service Level I coatings for the SPEO is required.

Proper maintenance of protective coatings inside containment (defined as Service Level I in NRC RG 1.54 Revision 3) is essential to the operability of post-accident safety systems that rely on water recycled through the containment to the suppression pool. Degradation of coatings can lead to clogging of ECCS suction strainers, which reduces flow through the system and could cause unacceptable head loss for the pumps. Regulatory Position C4 in NRC RG 1.54 Revision 3 describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program. ASTM D 5163-08 (Reference 1.6.57) and endorsed years of the standard in NRC RG 1.54 Revision 3 are acceptable and considered consistent with NUREG-2191, Section XI.S8.

The MNGP Protective Coating Monitoring and Maintenance AMP is a condition monitoring program, with scope that includes Service Level I coatings inside the MNGP primary containment on both steel and concrete substrates. Per the MNGP ASME Section XI, Subsection IWE AMP (B.2.3.29), coatings are a design feature of the base material and are not credited with managing loss of material.

The MNGP Protective Coating Monitoring and Maintenance AMP provides guidelines for the inservice coatings monitoring program for Service Level I coatings in accordance with ASTM D 5163-08. The AMP will use the aging management detection methods, inspector qualifications, inspection frequency, monitoring, trending, and acceptance criteria defined in ASTM D 5163-08, and inspects for any visible defects, such as blistering, crazing, cracking, flaking, peeling, rusting, and physical damage. The inspection interval is no greater than every three outages (6 years). The inspection report prioritizes repair areas as either needing repair during the same outage or as postponed to future outages, but under surveillance in the interim period. The assessment from periodic inspections and analysis of total amount of degraded or unqualified coatings in the containment is compared with the total amount of permitted degraded or unqualified coatings to provide reasonable assurance of ECCS operability. Individuals performing follow up inspections shall be trained in applicable reference standards in accordance with ASTM D5498 (Reference 1.6.58).

The characterization, documentation, and testing of defective or deficient coating surfaces is consistent with ASTM D 5163-08. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies. Assessment reports documenting inspection results are prepared by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, and prioritization of repairs.

NUREG-2191 Consistency

The MNGP Protective Coating Monitoring and Maintenance AMP, with enhancements, will be consistent without exception to the 10 elements of NUREG-2191, Section XI.S8, *Protective Coating Monitoring and Maintenance*, as modified by SLR-ISG-2021-03-STRUCTURES.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Protective Coating Monitoring and Maintenance AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Procedures will be revised to specify that thorough visual inspections shall be carried out on previously designated areas and on areas noted as deficient during the walk-through. When follow-up inspections beyond visual inspections are specified by the Nuclear Coatings Specialist, they will be performed by individuals trained and certified in the applicable reference standards of ASTM Guide D5498 for the inspection designated by the Nuclear Coatings Specialist.
5. Monitoring and Trending	Procedures will be revised to specify that any required coatings repairs be prioritized between the current or future outages.
6. Acceptance Criteria	Procedures will be revised to specify that if coating areas cannot be inspected, it will be noted in the inspection documentation with a reason why the inspection could not be conducted.
10. Operating Experience	Procedures will be revised to reference Position C4 of RG 1.54 Revision 3 for Maintenance of Service Level I Coatings.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions. NUREG-2191 as modified by SLR-ISG-2021-03-STRUCTURES, *Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance*, describes industry experience pertaining to coatings degradation inside containment and the consequential clogging of sump strainers including NRC IN 88-82, NRC Bulletin 96-03, NRC GL 04-02, and NRC GL 98-04. NRC RG 1.54, Revision 1, was issued in July 2000. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 are expected to be an effective program for managing degradation of Service Level I coatings. NRC RG 1.54 Revision 3 was issued in April 2017 and continues to provide guidance on maintenance of Service Level 1 coatings in Regulatory Position C4.

Plant-Specific Operating Experience

The condition of containment coatings for MNGP is assessed each refueling outage in accordance with the MNGP coating program procedures. The as-found condition is documented and compared to established acceptance criteria. Any degraded coating conditions are documented and evaluated to determine if repairs are required or if the condition should be trended or repaired in future outages. The condition of containment coatings has been found to be acceptable with no significant adverse conditions that would impact ECCS operability. Minor coating repairs have been initiated where warranted to maintain or improve the margins to the design limits with respect to degraded coatings in the containment. For example:

- In May 2015 inspection of the containment coatings was completed during the refueling outage. The condition of the containment coatings was found to be acceptable. No immediate corrective actions were required to meet design and licensing basis requirements. Some minor repairs were initiated to improve the coating material condition and margin with respect to the quantity of degraded coatings in the containment. The total quantity of degraded coatings remained within the administrative limits established by MNGP to ensure margin in the assumptions for the design basis calculation of the ECCS suction strainers.

- In May 2017 inspection of the containment coatings was completed during the refueling outage. The condition of the containment coatings was found to be acceptable. No immediate corrective actions were required to meet design and licensing basis requirements. Some minor repairs were initiated to improve the coating material condition and margin with respect to the quantity of degraded coatings in the containment. The total quantity of degraded coatings remained within the administrative limits established by MNGP to ensure margin in the assumptions for the design basis calculation of the ECCS suction strainers.

- In May 2019 inspection of the containment coatings was completed during the refueling outage. The condition of the containment coatings was found to be acceptable. No immediate corrective actions were required to meet design and licensing basis requirements. Some minor repairs were initiated to improve the coating material condition and margin with respect to the quantity of degraded coatings in the containment. The total quantity of degraded coatings remained within the administrative limits established by MNGP to ensure margin in the assumptions for the design basis calculation of the ECCS suction strainers.

- In May 2021 inspection of the containment coatings was completed during the refueling outage. The condition of the containment coatings was found to be acceptable. No immediate corrective actions were required to meet design and licensing basis requirements. Some minor repairs were initiated to improve the coating material condition and margin with respect to the quantity of degraded coatings in the containment. The total quantity of degraded coatings remained within the administrative limits established by MNGP to ensure margin in the assumptions for the design basis calculation of the ECCS suction strainers.

For outage Service Level 1 inspections, evaluations are performed on unacceptable coated surface areas. The administrative limit ensures margin between the quantity of degraded coating in containment and the design limit.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Protective Coating Monitoring and Maintenance AMP.

The MNGP Protective Coating Monitoring and Maintenance AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Protective Coating Monitoring and Maintenance AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualifications Requirements AMP, previously part of the Electrical Cables and Connections not Subject to 10 CFR 50.49 Environmental Qualification Requirements, is an existing AMP. This AMP provides reasonable assurance that the intended functions of cable and connection electrical insulation exposed to ALEs caused by heat, radiation and moisture can be maintained consistent with the CLB through the SPEO.

This AMP applies to accessible non-EQ electrical cable and connection electrical insulation material within the scope of SLR subjected to adverse (e.g., excessive heat, radiation, and/or moisture) localized environment(s). ALEs are identified through the use of an integrated approach which includes, but is not limited to, a review of relevant plant-specific and industry OE, a review of EQ zone maps, real time infrared thermographic inspections, conversations with plant personnel cognizant of specific area and room environmental conditions, etc. To facilitate the identification of an ALE, a temperature threshold and a radiation threshold will be identified in the plant implementing procedure for cable and connection insulation materials within the scope of this program.

Accessible non-EQ insulated cables and connections within the scope of SLR installed in ALEs are visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. The inspection of accessible cable and connection insulation material is used to evaluate the adequacy of inaccessible cable and connection electrical insulation. If visual inspections identify cable jacket and connection insulation surface anomalies, then testing may be performed. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. When a large number of cables and connections are identified as potentially degraded, a sample population is selected for testing. A sample of 20 percent of each cable and connection type with a maximum sample size of 25 is tested. The component sampling methodology includes a representative sample of in scope non-EQ electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selections is documented.

When acceptance criteria are not met, a determination is made as to whether the surveillance, inspection, or tests, including frequency intervals, need to be modified.

The first inspection for SLR is to be completed no later than six months prior to entering the SPEO. Recurring inspections are to be performed at least once every 10 years thereafter.

Plant specific OE is evaluated to identify in scope cable and connection insulation previously subjected to ALE during the initial PEO. Cable and connection insulation is evaluated to confirm that the dispositioned corrective actions continue to support in scope cable and connection intended functions during the SPEO.

Acceptance criteria under this AMP specifies that no unacceptable visual indications of cable and connection jacket surface anomalies should be observed. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. If testing is deemed necessary, the acceptance criteria for testing electrical cable and connection insulation material is defined in the work order for each cable and connection test and is determined by the specific type of test performed and the specific cable tested.

NUREG-2191 Consistency

The MNGP Electrical Insulation For Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements AMP with enhancements is consistent without exception to the 10 elements of NUREG-2191, Section XI.E1, *Electrical Insulation For Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Electrical Insulation For Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements AMP is enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise implementing documents to: • Identify the most limiting temperature, radiation, and moisture environments and their basis. Cable and connection inspections are performed for the most limiting insulation plant environments. • Review plant-specific OE for previously identified and mitigated ALEs for cumulative aging effects that could potentially impact service life.
4. Detection of Aging	Revise implementing documents to: • Evaluate plant-specific OE to identify in-scope cable and connection insulation previously subjected to ALE during the original PEO. Cable and connection insulation is evaluated to confirm that the dispositioned corrective

Element Affected	Enhancement
	actions continue to support in-scope cable and connection intended functions during the SPEO. • Identify that unacceptable visual indications of cable jacket and connection insulation surface anomalies that could potentially lead to a loss of intended function are subject to an engineering evaluation. If visual inspections identify degraded or damaged conditions, then testing may be performed. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. • When a large number of cables and connections are identified as potentially degraded, a sample population is tested. The sample would consist of 20 percent of each cable and connection type with a maximum sample size of 25. The following factors are considered in the development of the cable and connection insulation test sample: environment including identified ALEs (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. The component sampling methodology will utilize a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selection is documented.
6. Acceptance Criteria	Revise governing procedures to: • Identify that electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in MNGP procedures.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

- Industry OE has identified cable and connection insulation aging effects due to ALEs caused by elevated temperature, radiation, or moisture. For example, cable and connection insulation located near steam generators, pressurizers, or process may be subjected to an ALE. These environments have been found to cause degradation of electrical cable and connection electrical insulation that are visually observable, such as color changes or surface abnormalities. These visual indications along with cable condition monitoring can be used as indicators of cable and connection insulation degradation.

Plant-Specific Operating Experience

- In June 2012, a cable in the scope of SLR was identified as past its service life Due to observed cable insulation degradation. The cable was replaced with a new cable of higher quality.

- In March 2013, during a walkdown a cable was found to have cracking along the visible length of the jacket. The cause of the cracking was unclear. The cable was de-terminated and coiled in a cable tray section in the East turbine building. The CAP originator inspected all coiled cables in trays in the East Turbine Building for obvious signs of cable degradation. The coiled cables were pulled back to the tray to support the reactor feed pump replacement project. Only cables coiled within view of the scaffold were inspected. This was not a tactile inspection as the cables were not touched. Only two cables were found to have visible signs of degradation. There was not enough information to determine if this cable is in scope of SLR, but this OE provides objective evidence that existing maintenance practices effectively identify observable cable jacket deficiencies and subsequently implement effective corrective actions. This condition was corrected.

- During determination of a diesel generator cable in the scope of SLR for Tan Delta testing per a work order, the center phase of the cable had about a one-inch piece of insulation break off. The taped connection was very old and cable insulation may have fused to the tape used in the connection. The termination method was reviewed directly with the electrician who performed the task. After the degraded insulation was removed (one inch or less), the extended portion of the conductor was re-insulated using the appropriate UCI tape applied in accordance with plant procedures such that proper insulation was restored. Engineering evaluated this condition and discussed the repair implemented by the electricians. The repair was determined to be acceptable and thus did not affect the operability of the diesel generator.

- In September 2013, a determination was made that a plant ALE may have been missed for the Electrical Insulation for Electrical Cables and Connections Not Subject to CFR 50.49 Environmental Qualification Requirements AMP. The turbine front standard cabling was replaced in support of plant life extension over the last three cycles. The cable replacements were necessary due to degradation attributed to an ALE most likely caused by higher levels of radiation and/or heat. The cable condition monitoring program was tasked with managing the aging of conductor insulation material on cables, connectors and other electrical insulation material installed in ALEs caused by heat, radiation, or moisture. Once an adverse environment was identified a determination was to be made as to whether the same environment exists for inaccessible cables or connectors. The turbine front standard was not initially identified as an ALE under license renewal as these cables were considered not accessible per NUREG-1801, Section XI.E1. This cable is not in scope for SLR but provides objective evidence that existing maintenance practices effectively identify observable cable jacket deficiencies and subsequently implement effective corrective actions. A procedure change request was made to alter instructions to better address ALEs in reference work orders.

Effectiveness/Self-Assessment Reviews:

- 2020 – License Renewal Effectiveness Review

  AMP effectiveness is assessed at least every five years per NEI 14-12. A five-year effectiveness review was completed in March 2020, and no findings were identified related to the MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

- 2019 – License Renewal Phase IV Self-Assessment Plan

  A self-assessment was performed in preparation for the LR Phase IV NRC inspection. With respect to the MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, the format for the engineering work instruction did not clearly lay out the ten elements easily observed in most other instructions. The self-assessment determined that no actions were required.

- 2015- Select AMP Effectiveness Review

  Select MNGP AMPs were reviewed to verify the commitments, inspections, and relevant activities were scheduled and performed in accordance with the program. As a result, an AR was generated to update the engineering work instruction and to add the text for the relevant NRC commitment. The AMP was compared to GALL Revision 2 AMPs for Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements and Fuse Holders. The AMP was consistent with both.

Although some of the examples above were not determined to be age-related, the above OE provides objective evidence and additional confirmation to support industry OE that electrical insulation has not experienced a high degree of failures, that cable insulation issues are promptly identified and addressed through MNGPs CAP, and existing maintenance practices are effective.

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Electrical Insulation For Electrical Cables and Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements AMP with enhancements, will provide reasonable assurance that the effects of aging is managed so that the intended function(s) of components within the scope of the AMP is maintained consistent with the CLB during the SPEO.

B.2.3.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is an existing AMP, previously known as the Electrical Cables Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits Program, which provides reasonable assurance that the intended functions of electrical cables and connections that are not subject to the EQ requirements of 10 CFR 50.49 and are used in circuits with sensitive, high voltage, low-level signals exposed to ALEs caused by heat, radiation or moisture will be maintained consistent with the CLB through the SPEO. This AMP applies to high range radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low level current signal applications that are sensitive to reduction in electrical insulation resistance, within the scope of SLR. Electrical insulation used in electrical cables and connections may degrade more rapidly than expected when exposed to ALEs. An ALE is an environment that exceeds the most limiting environments, like temperature, radiation, and moisture, for the electrical insulation of cables and connectors. Exposure of electrical insulation to ALE caused by temperature, radiation, or moisture can cause age degradation resulting in reduced electrical insulation resistance, moisture intrusion related connection failures, or error induced by thermal transients. Reduced electrical IR causes shorts between conductors and shorts to ground. A reduction in electrical IR is a concern for all circuits but especially those with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation circuits, because a reduced IR may contribute to signal inaccuracies.

Identifying the existence of electrical insulation aging effects for cables and connections used in instrumentation circuits with sensitive, high-voltage, low-level current signals is performed through the use of either of two methods. In the first method, calibration results or findings of surveillance testing programs for the instrument loops are evaluated to identify the existence of electrical cable and connection insulation aging degradation. In the second method, direct testing of the cable system is performed.

Taking corrective actions, such as recalibration and circuit troubleshooting, if calibration, surveillance, or cable system test results do not meet the acceptance criteria. An engineering evaluation is performed when the acceptance criteria are not met. Such evaluations consider the significance of the calibration, surveillance, or cable system test results and whether the review of calibration and surveillance results or the cable system testing frequency needs to be increased.

NUREG-2191 Consistency

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Used in Instrumentation Circuits AMP is consistent without exception to the 10 elements of NUREG-2191, Section XI.E2, *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits AMP*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Used in Instrumentation Circuits AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise the implementing procedures to include documented periodic review of calibration test results for neutron monitors and radiation monitors within the scope of this program. MNGP to perform the first periodic review for second license renewal prior to the SPEO and at least every 10 years thereafter.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE Program and takes appropriate corrective actions.

Industry OE has identified that a change in temperature across a high range radiation monitor cable in containment can result in a substantial change in the reading of the monitor. Changes in instrument calibration can be caused by degradation of the circuit cable or connection electrical insulation and represents a possible indication of electrical cable degradation.

Plant-Specific Operating Experience

Intermediate Range Monitor (IRM) Issues

- Multiple ARs from the past 10 years include conditions where the IRM cables were not working properly. These conditions were due to the IRM cables being damaged over time during device exchanges, connectors failing, solder failing, and damage during testing. These resulted in improper signals, pulses, noises, or no signal at all.

  Examples included damaged wires, connectors requiring replacement, noisy signals, and failing testing criteria. The corrective action for each of these ARs varied between cable replacement, re-soldering connection pins, and restored/repaired cabling after identification. These ARs required cause evaluation, satisfactory testing, and return to service testing. Actions were performed per the work management process to return the IRM to an operable status.

Local Power Range Monitor (LPRM) Issues

- 2013 - During performance of a procedure for newly replaced LPRMs, 2 LPRMs failed to meet acceptance criteria for insulation resistance and voltage breakdown. Additionally, a third showed signs of degradation due to the cable being wetted.

  The detectors were dried out with a heat gun and then further dried with the use of a desiccant overnight. Tests were well above acceptance criteria and insulation resistance and voltage breakdown results were acceptable. As a result, all detectors were reconnected under the vessel.

Area Radiation Monitor Calibration Issues

- 2017 – An area radiation monitor (ARM) displayed a higher than expected signal when exposed to the calibrated source during maintenance. The signal became more erratic whenever the field technician caused movement or vibration near the sensor field connection. Additional ARM monitoring was established with remote monitoring in the control room.
- 2021 - During restoration, the signal input connector of an ARM failed due to a wire broken loose from its pin. Due to the connector's configuration and limited viewing opportunities, the exact break could not be determined at the time. This prevented the radiation monitor from receiving a signal from the detector and resulted in an "INOP" condition for the radiation monitor. Actions were performed per the work management process to return the ARM to an operable status.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020, and some minor enhancements were identified related to the MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Used in Instrumentation Circuits AMP. A minor enhancement and organization changes were made to the overall AMP document and references to ensure they were up to date.

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Used in Instrumentation Circuits AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements Used in Instrumentation Circuits AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is an existing AMP, previously titled as the Inaccessible Medium Voltage (2 kV to 34.5 kV) Cables Not Subject to 10 CFR 50.49 EQ Requirements Program. The purpose of the MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible medium-voltage power cables (operating voltages of 2 kV to 35 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

This AMP applies to inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ cables within the scope of SLR exposed to wetting or submergence (i.e., 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. Cable wetting or submergence that occurs for a limited time, as in the case of automatic or passive drainage, is not considered significant moisture for this AMP.

Periodic actions to mitigate inaccessible medium-voltage cable exposure to significant moisture include inspection for water accumulation in cable manholes and conduit ends and removing water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspections occur at least once annually with the first inspection for SLR completed no later than six months prior to entering the SPEO. Inspection frequencies will be adjusted based on inspection results including plant-specific OE but with a minimum inspection frequency of at least once annually. Inspections will also be performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Inspection of manholes (if equipped) with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE.

Parameters will be established for the initiation of an event driven inspection. Inspections will include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manually pumping of manholes or vaults, in preventing cable exposure to significant moisture. If water is found inside a manhole during an inspection, dewatering activities are initiated, the source of the water intrusion is determined, and cable insulation degradation of the cable is assessed.

Inaccessible non-EQ medium-voltage power cables within the scope of SLR exposed to significant moisture will be tested to determine the age-related degradation of their electrical insulation.

The first tests for SLR will be completed no later than six months prior to entering the SPEO, with subsequent tests performed at least once every 6 years thereafter. Cable testing depends on the cable type, application, and construction, and typically employs a combination of test techniques capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. MNGP specific inaccessible medium-voltage power cable procedures will be enhanced or developed to document inspection methods, test methods, and acceptance criteria for the in scope inaccessible power cables based on OE.

An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The acceptance criteria are defined for each cable test and is determined by the specific type of test performed and the specific cable tested. Acceptance criteria for inspections for water accumulation are defined by the direct indication that cable support structures are intact, and cables are not subject to significant moisture.

The aging management of the physical structures, including cable support structures of cable vaults/manholes is managed by the MNGP Structures Monitoring (B.2.3.33) AMP. The MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP scope will be added to existing MNGP procedures for governing its surveillance or maintenance program. The existing pertinent procedures will be updated to ensure all aging management activities align with NUREG 2191, Section XI.E3A.

NUREG-2191 Consistency

The MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.E3A, *Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements*, as modified by NRC SLR-ISG-2021-04-ELECTRICAL, *Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
1. Scope of Program	Revise implementing documents to ensure medium-voltage power cables energized less than 25% of the time are included within the scope of this program.
2. Preventive Actions	Revise implementing documents to ensure manhole inspections occur at least once annually.
2. Preventive Actions	Revise implementing documents to inspect manholes for water accumulation after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
2. Preventive Actions	Revise implementing documents to ensure manhole inspections include direct indication that the cables are not wetted or submerged, and that cable/splices and cable support structures are intact.
4. Detection of Aging Effects	Revise implementing documents to test medium-voltage power cables within the scope of this program at least once every six years.
6. Acceptance Criteria	Revise implementing documents to ensure manhole inspections include direct indication that the cable support structures are intact.

Operating Experience

Industry Operating Experience

OE has shown that medium-voltage power cable electrical insulation materials undergo increased age-related degradation either through water tree formation or other aging mechanisms when subjected to significant moisture. Inaccessible medium-voltage power cables subjected to significant moisture may result in an increased age-related degradation of electrical insulation. Minimizing exposure to significant moisture mitigates the potential for age-related degradation. The MNGP program will be based on the program description in NUREG-2191 XI.E3A, which in turn is based on industry OE.

Plant-Specific Operating Experience

The following examples of OE provide objective evidence that the MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to

10 CFR 50.49 Environmental Qualification Requirement AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

NRC GL 2007-01 requested licensees to provide information on the monitoring of inaccessible or underground electrical power cables feeding SR equipment conducted at each site. The GL detailed accounts of leaking duct banks, cable jacket tears, and multiple instances of submerged cables in manholes.

The MNGP response was summarized as follows:

- Three (3) medium-voltage power cables were replaced due to in-service failure.
- Three (3) cables [2 medium-voltage power cables] were replaced due to test acceptance criteria failures. Test method used was insulation resistance check with a megger.
- Four (4) cables [1 medium-voltage power cable] were replaced due to observed cable degradation. Observed brittle and cracking insulation was the basis for cable replacement.
- All cables replaced were butyl rubber insulated with a neoprene jacket supplied by General Electric.

The cable condition monitoring program (CCMP) at MNGP was initiated in 1998 to determine which cables are targeted for replacement based on assigned risk factors. MNGP has replaced cables under this program and has plans to replace other high-risk cables. MNGP is committed to implementing AMPs which will provide for additional monitoring of cable conditions.

A review of the 4 kV system health reports indicated RED status during 2014 -2015, then GREEN status from 2016-2018. This system health report covered mainly the performance of the 4 kV switchgear and did not indicate cable aging issues affecting or contributing towards the RED status years of 2014-2015.

A review of the 13.8 kV system health reports indicated GREEN status through 2019-2021 with no cable aging issues noted.

A CCMP self-assessment was conducted in 2012 with the following findings for improvement:

- The CCMP document did not include scoping methods, basis, and how cables in the scope of the program were being monitored, tested, and risk-ranked.
- Cables were not risk-ranked for submergence or wetting.
- Annual manhole inspections did not assure cables would not get submerged
- No manhole trending of dewatering frequency and cable submergence cases was evident.

- The CCMP did not provide guidance on actions when water is found in manholes.
- The CCMP did not provide for the reviewer, verifier, and qualification requirements to maintain the program products, including cable testing, and risk ranking spreadsheets [database].

The CCMP was enhanced to address/resolve these findings.

A search of the AR database in the CAP for underground medium-voltage cables and manholes revealed multiple ARs during the early implementation of this program (2010-2020 timeframe). The ARs indicated degrading insulations of underground medium-voltage power cables (from testing) that had led to cable replacements, and the manhole ARs did reflect a challenging high-moisture environment in select manholes absent of mandated event-driven inspections. Manhole water level trending and the addition of event-driven inspections will provide reasonable assurance that water levels in the manholes are maintained below the cables and their supports. Cable tests on a minimum 6-year frequency will consistently be conducted and records maintained for trending.

<u>Underground Medium-Voltage Power Cable Finding</u>

In May 2013, the CCMP had been without a program owner for six months. A corrective action was issued to establish a full-time position and fill it with a program owner to replace the interim back-up program owner. The position was filled in May 2014.

In May 2013, during performance of a maintenance procedure on the 12.5 kV loop, a fuse opened on the B phase cable. This affected power to the rotor storage, ISFSI, Menards, and the SAF buildings. Power was restored to the affected structures, and the located cable section was replaced. No direct cause of the cable failure was provided, but the same cable section and fuse blown has occurred before.

In September 2014, the Tan Delta testing results for a cable feeding the MET tower were outside acceptable values. A comparison was made to the last cable test WO, and the current test results were attributable to testing conditions (wet and rainy) and the condition of test boots (external dirt and moisture). The cable was not in scope of license renewal. No further actions were required.

In March 2021, there was not a CCMP coordinator qualified at MNGP. This condition existed since the most recent coordinator took a new position in late 2020. Four people in the fleet were qualified to the mentor guide. This CAP was documenting a finding in not having a qualified coordinator at the station. Both the primary and backup program owners are now qualified as of January 2022.

<u>Electrical Manhole Findings</u>

In March 2012, workers discovered 4 inches of water in two manholes while performing the weekly manhole inspection for water accumulations. The water was removed. Due to past water accumulation history with these manholes in 2009 and initiating 6 month inspections, drains were scheduled for installation in May 2012, but had yet to be installed. No cables were in scope of SLR.

In July 2013, handholes and manholes were found to contain water and mud. The water was removed. None of the cables associated with these handholes and manholes were in the scope of SLR.

In July 2014, handholes and manholes were found to contain water and mud. None of the cables associated with these handholes and manholes were in the scope of SLR. Water levels were recorded for trending and water was removed.

In June 2017, during the scheduled manhole inspection, water accumulations were found in multiple handholes and manholes. There were SR cables in one of the manholes, but the cables were not found to be submerged. Water was removed and levels were recorded for trending. Cables were inspected but had no signs of jacket/insulation degradation were found.

In August 2019, during the scheduled manhole inspection, water accumulations were found in several handholes and manholes. Debris (wires and leftover work materials) were also found. There were SR cables in two of the manholes; however, cables were not found submerged. Water and debris were removed, and water levels were recorded for trending.

In August 2020, during the scheduled manhole inspection, water accumulations were found in seven handholes and manholes. There were SR cables in two of the manholes, but no cables in any of the manholes were found submerged and no water marks on walls indicated water levels up to or exceeding the cable trays. Water was removed and water levels were recorded for trending. Cables were inspected but had no signs of jacket/insulation degradation.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Inaccessible Medium-Voltage Power Cables AMP.

The MNGP Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 EQ Requirements AMP, with enhancements, is informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Inaccessible Medium-Voltage Power Cables AMP, with enhancements, will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.39 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP. The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible and underground I&C cables that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO. The MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP applies to inaccessible and underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) I&C cables that are within the scope of SLR 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), which if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event-driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of the MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

This is a condition monitoring program. However, the MNGP Inaccessible I&C Cables AMP also includes periodic actions to prevent inaccessible I&C cables from being exposed to significant moisture. Periodic actions taken to mitigate inaccessible I&C cable exposure to significant moisture include inspection for water accumulation in cable manholes/vaults and conduit ends, and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for SLR completed prior to the SPEO. Inspections are also performed after event-driven occurrences, such as heavy rain, or flooding. The periodic inspection includes documentation that either automatic or passive drainage systems, or manual pumping of manholes or vaults, is effective in preventing inaccessible I&C cable exposure to significant moisture. Inspection of manholes (if equipped) with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE.

The aging management of the physical structures, including cable support structures of cable vaults/manholes is managed by the MNGP Structures Monitoring (B.2.3.33) AMP. The MNGP Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP scope will be added to existing MNGP procedures for governing its surveillance or maintenance program. The existing pertinent procedures will be updated to ensure all aging management activities align with NUREG 2191, Section XI.E3B, as modified by SLR-ISG-04-ELECTRICAL.

In addition to inspecting for water accumulation, visual inspections will be performed for I&C cables that are accessible during manhole inspections for jacket surface abnormalities, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the I&C cable electrical insulation. Inspection frequencies are adjusted based on inspection results, including plant-specific OE. The visual inspection of inaccessible I&C cables occurs at least once every six years and may be coordinated with the periodic inspection for water accumulation. The visual inspection of inaccessible I&C cables also includes a determination as to whether other adverse environments may exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system. Inaccessible (e.g., underground) I&C cables found to be exposed to significant moisture are evaluated to determine whether testing is required. If testing is recommended, initial cable testing is performed once on a sample population to determine the condition of the electrical insulation. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. Test results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain component intended function(s) throughout the SPEO based on the projected rate and extent of degradation.

A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. One or more tests may be required due to cable type, application, and electrical insulation to determine the age-related degradation of the cable. Inaccessible and underground I&C cables designed for continuous wetting or submergence are also included in the MNGP Electrical Insulation for Inaccessible I&C Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP as a one-time inspection and test. The need for additional tests and inspections is determined by the test/inspection results, as well as industry and plant-specific OE.

Testing of installed inservice inaccessible (e.g., underground) I&C cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage power cables or low-voltage power cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible I&C cables when testing is required in the MNGP Electrical Insulation for Inaccessible I&C Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

NUREG-2191 Consistency

The MNGP Electrical Insulation for Inaccessible I&C Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be consistent with the 10 elements of NUREG-2191, Section XI.E3B, *Electrical Insulation for Inaccessible I&C Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements*, as modified by SLR-ISG-2021-04-ELECTRICAL, *Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

Industry Operating Experience

OE has shown that cable electrical insulation materials undergo increased degradation through aging mechanisms when subjected to significant moisture. Inaccessible I&C cables subjected to significant moisture may result in an increased age-related degradation of the cables electrical insulation. Minimizing exposure to significant moisture mitigates the potential for age related degradation. The MNGP program will be based on the program description in NUREG-2191 XI.E3B, which in turn is based on industry OE.

Plant-Specific Operating Experience

The CCMP at MNGP was initiated in 1998 to determine which cables should be targeted for replacement based on assigned risk factors. MNGP replaced cables under this program and had plans to replace other high-risk cables. MNGP is committed to implementing AMPs which will provide for additional monitoring of cable conditions.

The following examples of OE provide objective evidence that the MNGP Electrical Insulation for Instrumentation and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

A CCMP self-assessment was conducted in 2012 whereby four areas for improvement were noted:

(1) Cables were not risk-ranked for submergence or wetting. This was addressed that risk-ranking is conducted with consideration of wet environment.

(2) Annual manhole inspections did not assure cables would not get submerged. This was addressed by stating that MNGP did not experience submerged cables in manholes but did assume that cables in underground embedded conduits may be subjected to submergence. Improvements to the manhole inspections were clarified in manhole inspection documents.

(3) No manhole trending of dewatering frequency and cable submergence cases was evident. This was addressed by stating that trending is being maintained and stored.

(4) CCMP Program did not provide guidance on actions when water is found in manholes. The program document was to include dewatering actions.

I&C Cable Findings

In April 2014, during a transformer current transformer (CT) feedback test, the technician performed a megger test. The megger results were much lower than usual. The station determined that the CT was accurate by lifting both wires at the transformer. No cause was specifically determined but assumed to be from cable insulation degradation in its underground routing environment. The transformer remained energized. A work order was generated to replace the bad cable section. The junction box fitting entry points were sealed, and weep holes were installed to prevent reoccurrence. Cable replacements and junction box rework were completed in May 2015.

In April 2014, during a transformer CT feedback test, the technician performed a megger test. The megger results identified degraded cables from a breaker in the breaker cabinet to the 345 kV house. The results were much lower than usual, and a work order was generated to locate the cables via ground penetrating radar, hydro excavating, and replacement of the degraded cables. Replacements were completed in May 2015.

In November 2019, a work order was performed to inspect and megger known degraded cabling for the screen wash fire pump motor. Upon initial inspection, a section of cabling needed replacement/rework, and was able to be successfully cut back and re-terminated to remove the cable/insulation degraded ends. Follow-up megger test results verified satisfactory condition of the replacement section. This occurrence was closed to trend.

Electrical Manhole Findings

In March 2012, workers discovered approximately 4 inches of water in two manholes while performing weekly manhole inspections for water accumulations. The water was removed. Due to past water accumulation history with these manholes in 2009 and initiating 6 month inspections, drains were scheduled for installation in May 2012, but had yet to be installed. No cables in these manholes were in the scope of SLR.

In June 2012, a program self-assessment identified findings involving manhole inspections. Underground cables in the program were not risk-ranked, no trending data existed for water levels found in the manholes during the inspections, and no guidance or corrective actions were provided when water levels are found in manholes. Suggested improvements to the program manhole inspection trending were highlighted to resolve these manhole inspection findings in the program.

In July 2013, handholes and manholes were found to contain water and mud. The water was removed. None of the cables in these manholes and handholes were in the scope of SLR.

In June 2017, during a scheduled manhole inspection, water accumulations were found in seven handholes and manholes. There were SR cables in one manhole, but the cables were not found to be submerged. Water was removed and levels were recorded for trending. The cables were visually inspected but had no signs of jacket/insulation degradation were found.

In August 2019, during a scheduled manhole inspection, water accumulations were found in several handholes and manholes. Debris (wires and leftover work materials) were also found. There were SR cables in two of the manholes, but water levels were below the cables. Water and debris were removed, and water levels were recorded for trending.

In August 2020, during a scheduled manhole inspection, water accumulations were found in seven handholes and manholes. There were SR cables in two of the manholes, but no cables in any of the manholes were found submerged, and no water marks on the walls indicating water levels up to or exceeding the cable trays. Water was removed and water levels were recorded for trending. The cables were inspected but no signs of degradation were observed.

The manholes within the scope of this new AMP will be visually inspected periodically based on water accumulation over time. Inspection frequencies will be adjusted based on inspection results including plant-specific OE but with a minimum inspection frequency of at least once annually (including event-driven inspections). Plant-specific OE will be used to adjust the inspection frequency for this AMP. The AMP will be informed and enhanced as additional plant-specific OE is accumulated to ensure cables are kept free from significant moisture.

OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The MNGP Electrical Insulation for Inaccessible I&C Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Electrical Insulation for Inaccessible I&C Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.40 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a new AMP for SLR. The purpose of the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is to provide reasonable assurance that the intended functions of inaccessible and underground low-voltage AC and DC power cables (i.e., typical operating voltage of less than 1,000 V, but no greater than 2 kV) that are not subject to the EQ requirements of 10 CFR 50.49 are maintained consistent with the CLB through the SPEO.

The MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP applies to inaccessible and underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) non-EQ low-voltage power cables, including those designed for continuous wetting or submergence, within the scope of SLR 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. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

This is a condition monitoring program. However, the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP also includes periodic actions to prevent inaccessible and underground low-voltage power cables from being exposed to significant moisture include inspection for water accumulation in cable manholes/vaults and conduit ends and removing or draining water, as needed. Inspections are performed periodically based on water accumulation over time. The periodic inspections occur at least once annually with the first inspections for SLR completed no later than prior to entering the SPEO. Additional tests and periodic visual inspections are determined by the test/inspection results and industry and plant-specific aging degradation OE with the applicable cable electrical insulation. Inspection of manholes (if equipped) with water level monitoring and alarms that result in consistent and subsequent pump out of accumulated water prior to wetting or submergence of cables can be performed at least once every five years, if supported by plant OE.

The aging management of the physical structures, including cable support structures of cable vaults/manholes, is managed by the MNGP Structures Monitoring AMP (B.2.3.33).

Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact. Dewatering systems (e.g., sump pumps and passive drains) and associated alarms (if installed) are inspected, and their operation verified periodically. The periodic inspection includes documentation of the effectiveness of either automatic or passive drainage systems, or manually pumping of manholes or vaults, in preventing cable exposure to significant moisture.

Inspections for water accumulation are also performed after event driven occurrences, such as heavy rain, rapid thawing of ice or snow, or flooding. Parameters are established for the initiation of an event driven inspection.

In addition to inspecting for water accumulation, visual inspections will be performed for low-voltage cables that are accessible during manhole inspections for jacket surface abnormalities is performed. Inspection frequencies are adjusted based on inspection results including plant-specific OE.

Inaccessible low-voltage power cables within the scope of SLR are periodically visually inspected for cable jacket surface abnormalities such as: embrittlement, discoloration, cracking, melting, swelling, or surface contamination due to the aging mechanism and effects of significant moisture. Visual inspection occurs at least once every 6 years with the initial inspection occurring no later than six months prior to entering the SPEO. The cable insulation visual inspection portion of the AMP uses the cable jacket material as representative of the aging effects experienced by the low-voltage power cable electrical insulation. Age-related degradation of the cable jacket may indicate accelerated age-related degradation of the electrical insulation due to significant moisture or other aging mechanisms. Visual inspection of inaccessible and underground low-voltage power cables also includes a determination as to whether other adverse environments may exist. Cables subjected to these adverse environments are also evaluated for significant aging degradation of the cable insulation system.

Inaccessible low-voltage power cables found to be exposed to significant moisture are evaluated (e.g., a determination is made as to whether a periodic or one-time test is needed for condition monitoring of the cable insulation system). Cable insulation systems that are known or subsequently found through either industry or plant-specific OE to degrade with continuous exposure to significant moisture (e.g., Vulkene and Raychem cross linked polyethylene) are also tested to monitor cable electrical insulation degradation over time. The specific type of test(s) will be a proven technique capable of detecting reduced insulation resistance or degraded dielectric strength of the cable insulation system due to wetting or submergence. One or more tests may be required due to cable application, construction, and electrical insulation material to determine the age-related degradation of the cable insulation.

The cable testing (if required) portion of the AMP utilizes sampling. The following factors are considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other inaccessible low-voltage power cables not tested and whether the tested sample population should be expanded. The specific type of test(s) determines, with reasonable assurance, in scope inaccessible low-voltage power cable insulation age-related degradation. Testing of installed inservice low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium voltage power cables or I&C cables subjected to the same or bounding environment, inservice application, cable routing, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed inservice inaccessible low-voltage power cables when testing is required in this AMP.

Acceptance criteria for water accumulation inspections are defined by the direct indication that cable support structures are intact, and cables/splices are not subject to significant moisture. Dewatering systems (e.g., sump pumps and drains) and associated alarms are inspected, and their operation verified to prevent unacceptable exposure to significant moisture. Acceptance criterion for visual inspection of cable jackets is no unacceptable signs of surface abnormalities that indicate excessive cable insulation aging degradation may exist. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The acceptance criteria for cable testing (if recommended) are defined for each cable test and are determined by the specific type of test performed and the specific cable tested.

If recommended, initial cable testing is performed once by utilizing sampling to determine the condition of the electrical insulation. Test results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the component intended functions throughout the SPEO based on the projected rate and extent of degradation.

NUREG-2191 Consistency

The MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be consistent without exception to the 10 elements of NUREG-2191, Section XI.E3C, *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements*, as modified by SLR-ISG-2021-04-ELECTRICAL, *Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance*.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

<u>Industry Operating Experience</u>

OE has shown that cable electrical insulation materials undergo increased degradation through aging mechanisms when subjected to significant moisture.

Inaccessible low-voltage power cables subjected to significant moisture may result in an increased age degradation of electrical insulation. Minimizing exposure to significant moisture mitigates the potential for age related degradation. The MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be based on the program description in NUREG-2191 XI.E3C, which in turn is based on industry OE.

<u>Plant-Specific Operating Experience</u>

By way of background, NRC IN 2002-12 informed licensees of observed submergence in water of electrical cables that feed SR equipment. The bulletin detailed accounts of leaking duct banks, cable jacket tears, and multiple instances of submerged cables in manholes. NRC IN 2010-26, Submerged Electrical Cables, informed licensees of other plants underground power cable failures citing lack of condition monitoring (testing) to detect cable insulation aging. NRC GL 2007-01 further cited NRC Bulletin 2002-12 and informed licensees of these cable failures and asked them to provide information on the monitoring of inaccessible or underground electrical cables. MNGP submitted a formal response to NRC GL 2007-01, under letter L-MT-07-04. This documented response summarized the MNGP underground low-voltage power cable-related positions / issues at that time as follows:

- Two in-SLR scope low-voltage power cables (one failure and one degraded insulation condition) were replaced in 1997 and 1999. The two cables had an average installed age of 26 years.

- Three not in-SLR scope low-voltage power cables (one test failure and two degraded insulation condition) were replaced in 1996, 2001, and 2005. The three cables had an average installed age of 30 years.

- All of the replaced low-voltage power cables were butyl rubber insulated with a neoprene jacket supplied by General Electric.

The CCMP at MNGP was initiated in 1998 to determine which cables should be targeted for replacement based on assigned risk factors. MNGP has replaced cables under this program and had plans to replace other high-risk cables. MNGP is committed to implementing AMPs which will provide for additional monitoring of cable conditions.

The following examples of OE provide objective evidence that the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB during the SPEO.

A review of a two-year (2019-2021) span of system health reports was conducted on the 125 VDC system with a comprehensive GREEN rating. Categories included equipment performance, prevention of equipment failures, long-term equipment reliability, and work management; all scoring GREEN status. No findings involved low-voltage power cable insulation failures or degradation.

A review of a two-year (2019-2021) system health review was conducted on the 480 V system with a comprehensive GREEN rating. Categories included equipment performance, prevention of equipment failures, long-term equipment reliability, and work management; all scoring GREEN status except work management scoring WHITE due to PM deferrals. No issues involved any low-voltage power cable insulation failures or degradation.

A CCMP self-assessment was conducted in July 2012. The CCMP self-assessment defined four areas for improvement:

(1) Cables are not risk-ranked for submergence or wetting. This was addressed that risk-ranking is conducted with consideration of wet environment.

(2) Annual manhole inspections do not assure cables do not get submerged. This was addressed by stating that MNGP does not experience submerged cables in manholes but do assume that cables in underground embedded conduits may be subjected to submergence. Improvements to the manhole inspections were clarified in manhole inspection documents.

(3) No manhole trending of dewatering frequency and cable submergence cases is evident. This was addressed by stating that trending is being maintained and stored on the site computer drive.

(4) CCMP Program does not provide guidance on actions when water is found in manholes. This was addressed by revising program document to include dewatering actions.

A search of the AR database in CAP for underground low-voltage power cables and manholes revealed multiple ARs (2010-2020 timeframe). The ARs did indicate degrading insulations of underground low-voltage power cables (from testing) that has led to cable replacements, and the manhole ARs did reflect a challenging high-moisture environment in select manholes. The manhole water level trending and the addition of event-driven inspections will provide reasonable assurance that water levels in the manholes are maintained below the cables and their supports.

Low-Voltage Power Cable Findings

In April 2013, during scheduled PM testing in the CCMP, a low-voltage power cable was megger tested with unacceptable results. The cable was routed in conduit known to be susceptible to water intrusion. The cable was fed from a motor control center (MCC) that supports radwaste and pre-coat reactor water clean-up (RWCU) filters that are not in the scope of SLR. The cable had butyl rubber insulation and was modified to isolate (disconnect) the bad cables allowing for a reduced load until funding and plant conditions allowed for cable replacements. The cable was not in the scope of SLR and the MCC bus was NSR.

In April 2015, MCC feeder cables had unacceptable megger results. These cables were replaced in 1998, and previous tests conducted in 2009 had low megger results. A work order was initiated to clean cables, replace a splice, retest, and sealing of the vault. Subsequent 5-year PM cable tests (2020) resulted in additional low megger readings and are being evaluated under a new CAP item. The MCC was not in the scope of SLR.

In March 2020, fan motor butyl rubber insulated cables, not an in the scope of SLR, had low megger test results, and were replaced and rerouted with Cross-Linked Polyethylene (XLPE) insulated cable with jacketed interlocked armor for improved moisture protection and short-circuit damage rating.

<u>Electrical Manhole Findings</u>

In March 2012, workers discovered approximately 4 inches of water in two manholes while performing the weekly manhole inspection for water accumulations. The water was removed. Due to past water accumulations history with these specific manholes in 2009 and performing 6-month inspections, drains were scheduled for installation in May 2012, but have yet to be installed. None of the cables were in scope of SLR.

In July 2012, a program self-assessment identified findings involving manhole inspections. Underground cables in the program were not risk-ranked, no trending data existed for water levels found in the manholes during the inspections, and no guidance or corrective actions were provided when water levels are found in manholes. Improvements to program trending were implemented under another AR to resolve these manhole inspection findings in the program.

In July 2013, handholes and manholes were found to contain water and mud. The water was removed. None of the cables in these manholes and handholes were in the scope of SLR.

In July 2015, during an observation of cable testing and cable splicing activities, substantial rain occurred on two different occasions in the previous week resulting in submerged cables. This inspection followed a week of significant rainfall, whereby the natural drainage through the floor was overwhelmed by the ingress of rainwater. When the rainfall subsided, the manhole naturally drained (from the bottom of the manhole) in a relatively short period of time. Cable splices were reworked/replaced. Failure of the manhole seals (while the manhole is situated below grade on all four sides) was also a contributor. Previous cable tests of the cables within the manhole have demonstrated insulation degradation, but no new cable degradation was observed. Corrective actions included tar-sealing the vault cover and consideration to modify ground level or raise the manhole walls above ground level.

In June 2017, during the scheduled manhole inspection, water accumulations were found in several handholes and manholes. There were SR cables in one of the manholes, but the cables were not found to be submerged. Water was removed and levels were recorded for trending. The cables were visually inspected but had no signs of jacket/insulation degradation.

In August 2019, during a scheduled manhole inspection, water accumulations, or evidence of water, were found in several handholes and manholes. There were SR cables in two manholes, but water levels were below the cables. The water and debris were removed, and water levels were recorded for trending.

In August 2020, during a scheduled manhole inspection, water accumulations were found in seven handholes and manholes. There were SR cables in two of the manholes, but no cables in any of the manholes were found submerged, and no water marks were on the walls indicating water levels up to or exceeding the cable trays. The water was removed, and water levels were recorded for trending. The cables were inspected but no signs of degradation were observed.

The manholes within the scope of this new AMP will be visually inspected periodically based on water accumulation over time. Inspection frequencies will be adjusted based on inspection results including plant-specific OE but with a minimum inspection frequency of at least once annually (including event-driven inspections). Plant-specific OE will be used to adjust the inspection frequency for this AMP. The AMP will be informed and enhanced as additional plant-specific OE is accumulated to ensure cables are kept free from significant moisture. OE will be reviewed such that if there is an indication that the effects of aging are not being adequately managed, a corrective action will be initiated to either enhance the AMP or implement new AMPs, as appropriate. In addition, AMP effectiveness will be assessed at least every five years per NEI 14-12.

The MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be informed and enhanced, when necessary, through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG 2191, Appendix B.

Conclusion

The MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the MNGP Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.41 Metal-Enclosed Bus

The MNGP Metal-Enclosed Bus AMP, previously known as the Bus Duct Inspection Program, is an existing condition monitoring program. The purpose of the MNGP MEB AMP is to provide reasonable assurance that the intended functions of metal enclosed buses in scope of SLR are maintained consistent with the CLB through the SPEO.

This AMP provides for the inspection of the internal portions of the MEB to be completed prior to the SPEO and conducted every 10 years thereafter. Internal portions (bus enclosure assemblies) of the MEB are inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus electrical insulation material is inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation induced oxidation, moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, discoloration, or swelling, which may indicate overheating or aging degradation. The internal bus insulating supports are inspected for structural integrity and signs of cracks. The acceptance criteria of the visual inspections are that MEB electrical insulation materials are free from unacceptable regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. MEB internal surfaces show no indications of unacceptable corrosion, cracks, foreign debris, excessive dust buildup, or evidence of moisture intrusion.

The external MEB surfaces and structural supports will be inspected prior to the SPEO and conducted every 10 years thereafter under the Structures Monitoring AMP. The external portions of the MEB, including accessible gaskets, boots, and sealants, are also inspected for hardening or loss of strength due to elastomer degradation that could permit water or foreign debris to enter the bus. MEB external surfaces and structural supports are inspected under the MNGP Structures Monitoring AMP for loss of material due to general, pitting, and crevice corrosion. Accessible elastomers (e.g., gaskets, boots, and sealants) show no indications of unacceptable surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength. MEB external surfaces are free from unacceptable loss of material due to general, pitting, and crevice corrosion.

A sample of MEB bolted bus connections will be tested prior to the SPEO and tested using thermography or by measuring connection resistance using a micro ohmmeter. This is done every 10 years thereafter to ensure the connections are not experiencing increased resistance due to loosening of bolted bus duct connections caused by repeated thermal cycling of connected loads. A sample of 20 percent with a maximum sample of 25 constitutes a representative bolted bus connection sample size.

MEB bolted connections will be required to be within the acceptable resistance value appropriate for the application. If thermography is used, the MNGP thermography program utilizes a prioritization matrix for anomalies. MEB bolted connections shall be below the maximum allowed temperature for the application. As an alternative to measuring connection resistance or thermography of bolted connections for accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., visual inspections of insulation material may be used to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. If an alternative visual inspection is used to check MEB bolted connections, the first inspection will be completed prior to the SPEO and every 5 years thereafter.

NUREG-2191 Consistency

The MNGP Metal-Enclosed Bus AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.E4, *Metal-Enclosed Bus*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Metal-Enclosed Bus AMP will be enhanced as follows, for alignment with NUREG 2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise procedures to: • Include inspection of accessible elastomers (e.g., gaskets, boots, and sealants) for degradation including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening or loss of strength. • Perform an engineering evaluation of MEB segments that are not accessible for inspection. The evaluation can be based on results of accessible MEB inspections, tests, or other analysis.
4. Detection of Aging Effects	• Include inspection of accessible elastomers (e.g., gaskets, boots, and sealants) for degradation including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening or loss of strength. • Inspect bolted connection not covered with heat shrink tape, sleeving, insulating boots, etc. for

Element Affected	Enhancement
	corrosion, loose connections and hardware including cracked or split washers. • Define a representative sample size as 20 percent of the accessible bolted connection population, with a maximum of 25. Clarify that if visual inspections are used as an alternative to resistance measurements or thermography, inspections will be performed prior to the SPEO and every five years thereafter.
6. Acceptance Criteria	• Include inspection of accessible elastomers (e.g., gaskets, boots, and sealants) for degradation including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening or loss of strength. • Inspect bolted connection not covered with heat shrink tape, sleeving, insulating boots, etc. for corrosion, loose connections and hardware including cracked or split washers.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE program and takes appropriate corrective actions.

- Industry experience has shown that failures have occurred on MEBs caused by cracked electrical insulation and moisture or debris buildup internal to the MEB. Experience also has shown that bus connections in the MEBs exposed to appreciable ohmic heating during operation may experience loosening due to repeated cycling of connected loads. MNGP manages this OE by taking corrective actions for cracked insulation such as cleaning, replacement, and repair. MNGP also takes corrective actions for loose connections by tightening when needed.

  MNGP inspects and torques bolted connections in their implementing procedures. MNGP does not use splice plate connections and already utilizes copper bus bars. MNGP successfully addresses the industry OE in the Metal-Enclosed Bus AMP.

Plant-Specific Operating Experience

- In September 2017, MNGP electrical maintenance performed License Renewal visual inspections of a transformer and associated buses. The inspection identified moisture inside of a 13.8 kV bus due to the condition of the metal bus door gaskets. The condition was noted for trending. The gaskets were replaced, and no further actions were needed

- In September 2017, MNGP electrical maintenance performed License Renewal visual inspections of a transformer and associated buses. The inspection found that some joints on both the 4 KV and 13.8 KV MEB had small openings from misalignment during initial fabrication. The openings on the metal enclosed bus were sealed. Although not an aging effect, this shows that the inspections are effective in identifying issues and taking corrective action.
- In March 2013, during a bus duct inspection, brittle insulating tape was observed in one location at a 90 degree bend in the bus. This was not a bolted connection and there was no evidence of overheating of the tape. The tape remained intact but was replaced. Bolted connections that were taped did not exhibit embrittlement of the tape.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Metal-Enclosed Bus AMP.

The MNGP Metal-Enclosed Bus AMP will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Metal-Enclosed Bus AMP with enhancements will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

B.2.3.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification (EQ) Requirements AMP is an existing AMP for SLR. This AMP provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the EQ requirements of 10 CFR 50.49 and susceptible to age-related degradation resulting in increased resistance are maintained consistent with the CLB through the SPEO.

This AMP is a condition monitoring program that manages the aging mechanisms and effects that result in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation of the metallic portions of electrical cable connections within the scope of SLR.

This AMP focuses on the metallic parts of the electrical cable connections. Wiring connections internal to an active assembly are considered part of the active assembly and, therefore, are not within the scope of this AMP. This program does not apply to high voltage (>35 kV) switchyard connections. Cable connections covered under the Environmental Qualification of Electric Equipment program are not included in the scope of this program

One-time testing, on a representative sample of each type of non-EQ electrical cable connections within the scope of SLR, is performed prior to the SPEO. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. The specific type of test performed will be determined prior to the initial test and will be a proven test for detecting loose connections, such as thermography, contact resistance testing, or other appropriate testing. One-time testing provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. Depending on the findings of the one-time test, subsequent testing may have to be performed on a ten-year recurring basis. The following factors are considered for sampling: voltage level (medium and low voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. The first tests and evaluation of results for SLR are to be completed prior to the SPEO.

As an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials may be used to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO and at least every 5 years thereafter. The basis for performing only the alternative visual inspection to monitor age-related degradation of cable connections will be documented.

The acceptance criteria for each inspection or test will be defined by the specific type of inspection or test performed for the specific type of cable connection. Cable connections should not indicate abnormal temperatures for the application when thermography is used. Alternatively, connections should exhibit a low resistance value appropriate for the application when resistance measurement is used. When the visual inspection alternative for covered cable connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination is suitable in indicating that the covered cable connection components are not loose. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could potentially lead to a loss of intended function.

NUREG-2191 Consistency

The MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, with enhancements, is consistent without exception to the 10 elements of NUREG-2191, Section XI.E6, *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements*.

Exceptions to NUREG-2191

None.

Enhancements

The MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be enhanced as follows, for alignment with NUREG-2191. The enhancements are to be implemented no later than 6 months prior to entering the SPEO.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise implementing documents to: • Identify that the SLR program will be implemented by the evaluation of one-time testing results for a representative sample of connections that are within the scope of SLR and not subject to the requirements of the Environmental Qualification program.
4. Detection of Aging Effects	Revise implementing documents to: • Perform a one-time test, the results of which are evaluated to determine if periodic testing of cable connections is warranted. This initial evaluation of test results from the basis of site-specific operating experience (OE) for age-related degradation and informs the need for subsequent testing on a 10-year periodic basis. The justification and technical basis for

Element Affected	Enhancement
	not performing subsequent periodic testing are documented. • Define a representative sample size as 20 percent of the accessible connector type population, with a maximum sample of 25 per connection type. • Include an alternative to measurement testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc. MNGP may use a visual inspection of insulation material to detect surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed prior to the SPEO and at least every 5 years thereafter.
6. Acceptance Criteria	Revise implementing documents to: • Denote that cable connections should not indicate abnormal temperatures for the application when thermography is used. Alternatively, connections should exhibit a low resistance value appropriate for the application when resistance measurement is used. • Denote the following acceptance criteria, if the visual inspection of covered cable connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination indicates the covered cable connection components are not loose.

Operating Experience

Industry Operating Experience

MNGP evaluates industry OE items for applicability per the OE program and takes appropriate corrective actions.

- Electrical cable connections exposed to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation during operation may experience increased resistance of connection. There have been limited numbers of age-related failures of cable connections reported. MNGPs OE with connection reliability and aging effects demonstrates the AMP effectiveness of GALL-SLR Report AMP XI.E6, *Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental*

Qualification Requirements, including the program's capability to detect the presence or noting the absence of aging effects for electrical cable connections.

Plant-Specific Operating Experience

A search performed of MNGP OE for SLR, spanning the time frame from January 2012 through June 2021, returned the following ARs related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program:

- In May 2012, an adverse trend for a control rod drive position backlight indication of green at positions other than 00, was identified. In support of an apparent cause evaluation (ACE), a thermography test found that the rod position information system panel had a delta temperature of approximately 70°F at the terminal point. The condition extends to the other connections in the same panel, which were vulnerable to the same failure mechanisms, as the power and common connections were arranged in a similar bus configuration and were operating within the same environment over the same period of time. The ACE showed numerous instances of green control rod position backlight indication for positions other than full-in (00) at the full core display were due to inadequate power and / or common connections to the card file system within the panel. An outage work order inspected the bus connections, terminal screws, and lugs and made repairs or tightened as necessary. Work was completed and post-maintenance testing was satisfactory per a related work order.

- During the investigation of erratic indication (spiking) on the mid-range recorder for the B stack wide range gas monitor (WRGM) the cable for the midrange detector was found to be too short to allow any replacement of connectors. The connections were cleaned, and efforts were made to duplicate the spiking but no noise was noted. The monitor was in service for approximately 6 days with no abnormality noted on the recorder. The procedure steps for the source check response were satisfactory. Whenever cable connectors are replaced for cables that have been installed for a long period of time, the cable length is commonly shortened. No further actions were required at the time. The cables in question were functioning properly and have no known issues other than inadequate length to allow for future connector replacement. This issue did not affect the operability of the B stack WRGM.

Although some of the examples above were not determined to be age-related, the above OE provides objective evidence and additional confirmation to support industry OE that electrical connections have not experienced a high degree of failures, that cable connection issues are promptly identified and addressed through MNGPs CAP, and existing maintenance practices. The one-time implementation of the MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP will be effective in ensuring that component intended functions are maintained consistent with the CLB through the SPEO.

AMP effectiveness will be assessed at least every five years per NEI 14-12. A 5-year effectiveness review was completed in March 2020 and no findings were identified related to the MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

The MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry OE, including research and development, such that the effectiveness of the AMP is evaluated consistent with the discussion in NUREG-2191, Appendix B.

Conclusion

The MNGP Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP is a one-time program that will be implemented prior to the PEO. The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP with enhancements will provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of components within the scope of the AMP will be maintained consistent with the CLB during the SPEO.

APPENDIX C

RESPONSE TO BWRVIP LICENSE RENEWAL APPLICANT ACTION ITEMS

MONTICELLO NUCLEAR GENERATING PLANT

SUBSEQUENT LICENSE RENEWAL APPLICATION

Of the BWRVIP reports credited within MNGPs SLR AMPs, the following include NRC SERs that include action items applicable to license renewal applicants:

- BWRVIP-18-R2-A; BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines
- BWRVIP-25-R1-A; BWR Core Plate Inspection and Flaw Evaluation Guidelines
- BWRVIP-26-A; BWR Top Guide Inspection and Flaw Evaluation Guidelines
- BWRVIP-27-A; BWR Vessel and Internals Project, BWR Standby Liquid Control System/Core Plate Delta-P Inspection and Flaw Evaluation Guidelines
- Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations AMP)
- BWRVIP-38; BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- BWRVIP-41; BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (Revision 4)
- BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations AMP)
- BWRVIP-48-A, BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines (Credited in BWR Vessel ID Attachment Weld AMP)
- BWRVIP-49-A, BWR Instrument Penetration Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations AMP)
- BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guideline for License Renewal
- BWRVIP-76-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines (Revision 1)
- BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines
- BWRVIP-183-A, BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines

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.

It is recognized that the first three action items from each of the license renewal SERs applicable to the above BWRVIP reports are fundamentally identical, with the exception of BWRVIP-139-R1-A. For that reason, they are combined in the table and addressed together. These are addressed in Table C-1, with BWRVIP-specific action items addressed in Table C-2.

Table C-1	
Common Action Items from BWRVIP-18 R2-A, -25, -26-A, -27-A, -38, -41 R3, -47-A, -48-A, -49-A, -74-A, -76-R1-A	
Action Item Description	**MNGP Response**
BWRVIP-All (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 AMPs 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 MNGP have been reviewed and MNGP AMPs have been verified to be bounded by the reports. Additionally, MNGP is committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the SPEO. These commitments are included in SLRA Appendix A, Section A.4. 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 NRC final approval of the guideline. Commitments are administratively controlled in accordance with the requirements of 10 CFR Part 50, Appendix B.
BWRVIP-All (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 USAR supplements are included in SLRA Appendix A. The USAR supplements include a summary description of the programs and activities specified as necessary for managing the effects of aging per the BWRVIP reports.

Table C-1	
Common Action Items from BWRVIP-18 R2-A, -25, -26-A, -27-A, -38, -41 R3, -47-A, -48-A, -49-A, -74-A, -76-R1-A	
Action Item Description	**MNGP Response**
BWRVIP-All (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 AMR 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 that are required to meet the requirements of the BWRVIP reports during the SPEO. Reference SLRA Appendix D.

Table C-2	
BWRVIP-18-Revision 2A, Core Spray Internals Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-18 (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 core spray internal components.	Cumulative fatigue damage is a potential TLAA issue identified for all reactor vessel internal components. TLAA is used to manage cumulative fatigue damage for reactor vessel internal components as discussed in SLRA Section 4.3.4.

Table C-2	
BWRVIP-25-Revision 1-A, Core Plate Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-25-R1-A (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.	Preload of the rim hold-down bolts is required to prevent lateral motion of the core plate for those plants that do not have core plate wedges installed. Stress relaxation of the RPV core plate rim hold-down bolts has been identified as a TLAA issue as evaluated in SLRA Section 4.2.9.
BWRVIP-25-R1-A (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.	As evaluated in BWRVIP-25-Revision 1-A Appendix I, rim hold-down bolt inspections are not required as documented in SLRA Section 4.2.9.

Table C-2	
BWRVIP-26-A, BWR Top Guide Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-26-A (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 of the top guide was calculated to have exceeded the fluence threshold during the initial PEO. As such, baseline inspections of the top guide grid beam began in 2011. The reinspection interval and flaw evaluation guidance identified in BWRVIP-183 will continue to be implemented through the SPEO as implemented by the BWR Vessel Internals AMP (B.2.3.7) . The program requires that at least 10 percent of the grid beam cells containing control rod blades will be inspected every 12 years and has already completed the initial requirement to inspect at least 5 percent within 6 years. The inspections are performed using the enhanced visual inspection technique, EVT-1.

Table C-2	
BWRVIP-27-A, BWR Standby Liquid Control System/Core Plate Delta-P Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-27-A (4) Applicants referencing the BWRVIP-27-A 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 all reactor vessel internal components. TLAA is used to manage cumulative fatigue damage for the SLC System/core plate dP penetration as discussed in SLRA Section 4.3.4.

Table C-2	
BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-47-A (4) Applicants referencing the BWRVIP-47-A 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 all reactor vessel internal components. TLAA is used to manage cumulative fatigue damage for reactor vessel incore instrumentation and CRD penetrations as discussed in SLRA Section 4.3.4.

Table C-2	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-74-A (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 scope of license renewal. The nozzles and VFLD piping are fabricated of carbon steel. Loss of material is managed by the One-Time Inspection AMP (B.2.3.20) and Water Chemistry AMP (B.2.3.2).
BWRVIP-74-A (5) LR applicants shall describe how each plant-specific AMP 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 AMPs credited for managing aging of reactor pressure vessel components. Descriptions of the AMPs credited for managing the reactor pressure vessel are described in Appendix B. These descriptions include any program element that deviates from the NUREG-2191 program element, and any enhancements that are required to meet NUREG-2191 requirements.

Table C-2	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-74-A (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 AMP (B.2.3.2) is consistent with NUREG-2191, XI.M2, *Water Chemistry*, as modified by SLR-ISG-2021-02-MECHANICAL with one exception and meets the requirements of the latest BWRVIP Water Chemistry guidelines to help ensure the long-term integrity of the reactor vessel and internals. The exception taken in the Water Chemistry AMP does not impact meeting these requirements. AMPs that utilize inspections to perform condition monitoring of reactor pressure vessel and internal components to identify cracking also credit the Water Chemistry AMP to mitigate cracking of reactor vessel components, including the BWR Vessel Internals (B.2.3.7), BWR Vessel ID Attachment Welds (B.2.3.4), BWR Penetrations (B.2.3.6), and BWR Stress Corrosion Cracking (B.2.3.5) AMPs.
BWRVIP-74-A (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 AMP (B.2.3.19) will utilize the *Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR)* program per BWRVIP-321-A for the SPEO.

Table C-2 BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-74-A (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 4.3.3. Fatigue TLAAs are managed by the Fatigue Monitoring AMP (B.2.2.1) to ensure that cumulative fatigue usage will not exceed 1.0. Environmental fatigue for reactor vessel components is evaluated in SLRA Section 4.3.7.
BWRVIP-74-A (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 Part 50, Appendix G requirements for the SPEO as discussed in SLRA Section 4.2.4.
BWRVIP-74-A (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 SPEO were determined using methods consistent with RG 1.99, Revision 2. This is discussed as a TLAA in SLRA Section 4.2.2. MNGP vessel welds are made with E-8018 G electrodes using the shielded metal arc welding process, different from submerged arc welds which are limiting.

Table C-2	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-74-A (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, FSER, 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 second renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the staff's July 28, 1998, FSER. The MNGP evaluation is bounded by Table 1 of the FSER. Relief from the inservice inspection of the circumferential welds during the SPEO is discussed in SLRA Section 4.2.5. MNGP procedures have been established for overpressure events and operator training was originally committed to at MNGP as part of BWRVIP-05 implementation.
BWRVIP-74-A (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 that are evaluated in SLRA Section 4.2.6.
BWRVIP-74-A (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 SPEO, as discussed in SLRA Section 4.2.1.1.

Table C-2	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-74-A (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.	There are currently no indications which have been analytically evaluated to be acceptable through the end of the PEO. As such, there are no TLAAs for the SPEO.

Table C-2	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-76-R1-A (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 AMP (B.2.3.7) implements BWRVIP-76-A requirements including guidance within BWRVIP-76-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-A for evaluation of crack growth. The current guidance references BWRVIP-14-A and BWRVIP-99-A for crack growth rates and BWRVIP-100-A for fracture toughness values. The implementing procedures for the BWR Vessel Internals AMP (B.2.3.7) include the requirement to incorporate new guidance within new or revised BWRVIP reports. This assures that any emerging inspection guidelines developed by the BWRVIP for these core shroud welds will be incorporated into the program.
BWRVIP-76-R1-A (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.	The core shrouds have not been modified to include tie rod repairs.

Table C-2	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-76-R1-A (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 (2) 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 affects 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 AMPs 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 (including welds) is fabricated from stainless steel material. Cumulative fatigue damage for the core shroud has been identified as a TLAA as discussed in SLRA Section 4.3.4. 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.2.3.7) and Water Chemistry (B.2.3.2) AMPs will be used to manage cracking and loss of material due to pitting and crevice corrosion during the SPEO.

Table C-2	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-76-R1-A (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 (including welds) is fabricated from stainless steel material. No core shroud repair assembly components have been added. Therefore, core shroud components that are made from materials other than stainless steel are not addressed.
BWRVIP-76-R1-A (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 AMP (B.2.3.7) implements BWRVIP-76-R1-A requirements including guidance within BWRVIP-76-R1-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 and BWRVIP-99-A. The AMP basis document and implementing procedures for the BWR Vessel Internals program include reference to applicable BWRVIP reports including BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A for evaluation of crack growth.

Table C-2	
BWRVIP-139-R1-A, BWR Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
BWRVIP-139-R1-A (1) Aging Effects and Mechanisms Not Assessed or Managed in TR No. BWRVIP-139-R1-A, 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-R1-A, Appendix B. b. For those BWR license renewal applicants that identify additional	The MNGP replacement steam dryer is a Westinghouse Nordic steam dryer; therefore BWRVIP-139-R1-A is not applicable per Limitation No. 1.

Table C-2	
BWRVIP-139-R1-A, BWR Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
AERMs beyond those listed in BWRVIP-139-R1-A, 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)	
BWRVIP-139-R1-A (2) Referencing of the BWRVIP-139-R1-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-R1-A 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-R1-A 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.	The MNGP replacement steam dryer is a Westinghouse Nordic steam dryer; therefore BWRVIP-139-R1-A is not applicable per Limitation No. 1.
BWRVIP-139-R1-A (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	The MNGP replacement steam dryer is a Westinghouse Nordic steam dryer; therefore BWRVIP-139-R1-A is not applicable per Limitation No. 1.

Table C-2	
BWRVIP-139-R1-A, BWR Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**MNGP Response**
conforms to the definition of TLAA, the applicants shall: a. include the TLAA in the LRA in accordance with the requirements in 10 CFR 54.21(c)(1) b. 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 c. 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.	

In addition to the currently existing applicant action items, MNGP will implement the guidance in BWRVIP-315 to support extended operations. BWRVIP-315 includes proposed enhancements and revisions to the existing BWRVIP reports which are identified for operation beyond 60 years. These enhancements and revisions are noted in Table C-3 below, alongside the applicant action items.

Table C-3	
BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**MNGP Response**
BWRVIP-26-A To implement the guidance in BWRVIP-315, BWRVIP-26-A requires enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include a clarification of the fluence dependent limitations associated with flaw evaluations.	This change is incorporated into the BWR Vessel Internals AMP (B.2.3.7), however, as this is clarifying in nature there are no actions required to implement.
BWRVIP-41-R4-A To implement the guidance in BWRVIP-315, BWRVIP-41-R4-A requires enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include editorial changes regarding the operating service life, a defined screening thresholds of accumulated neutron fluence for embrittlement and irradiation enhanced stress relaxation, defined actions for CASS components which exceed this threshold, and refined inspection exemption criteria.	Further evaluation item 3.1.2.2.13 evaluates the embrittlement screening threshold added to BWRVIP-41 using the 80 year fluence data for each component in SLRA Section 4.2.1.2. Components which exceed the threshold are dispositioned in accordance with the guidance in newly added Section 5.6 of BWRVIP-41-R4-A. Any scope expansion exceptions will adhere to the additional criteria in newly added item 3.2.8.1.2.3 of BWRVIP-41-R4-A. Further evaluation item 3.1.2.2.14 evaluates the irradiation enhanced stress relaxation screening thresholds added to BWRVIP-41 using the 80 year fluence data for each component in SLRA Section 4.2.10. Components which exceed the threshold are dispositioned in accordance with the guidance in newly added Section 3.2.7 of BWRVIP-41-R4-A.

Table C-3	
BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**MNGP Response**
BWRVIP-47-A To implement the guidance in BWRVIP-315, BWRVIP-47-A requires enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include editorial changes regarding the operating service life and appropriate flaw evaluation methodologies.	The guidance provided regarding flaw evaluations is incorporated into the BWR Vessel Internals AMP (B.2.3.7) however, as this is clarifying in nature there are no actions required to implement.
BWRVIP-76-R2 To implement the guidance in BWRVIP-315, BWRVIP-76-R2 requires enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include a clarification of the fluence dependent limitations associated with flaw evaluations for core shroud repair hardware.	MNGP does not have core shroud repair hardware installed and the changes are not applicable. The changes provided in BWRVIP-315 are intended for BWRVIP-76-R2 which is not implemented by MNGP.

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 PEO.

No Technical Specification changes or additions were identified as necessary to manage the effects of aging during the SPEO and as such no Technical Specification changes or additions are included with this SLRA.